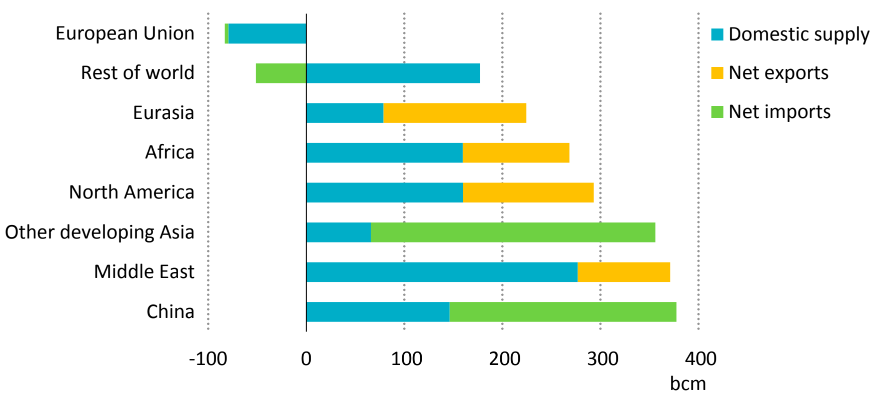
Outlook for natural gas

Does cheap mean cheerful?

SUMMARY

- Over the next two decades, global demand for natural gas grows more than four-times faster than demand for oil in the Stated Policies Scenario. Natural gas sees broad-based growth across the energy economy, in contrast to oil where growth is concentrated in parts of the transport sector (trucks, shipping and aviation) and petrochemicals.
- Developing Asian economies account for half of the global growth in natural gas demand and almost all of the increase in traded volumes. By 2040, they consume one-quarter of the world's gas production, much of it sourced from other regions. By 2040, the average gas molecule travels over 5 000 kilometres to reach consumers in developing Asian markets, nearly twice as far as today.

Figure 4.1 ⊳ Change in gas supply balance by region in the Stated Policies Scenario, 2018-2040



Most of the gas produced is consumed within the region where it is extracted. Developing countries in Asia underpin most of the growth in gas imports.

- China's natural gas consumption increased by 33% in just two years (2017-18). This massive expansion is having wide-ranging effects on the global liquefied natural gas (LNG) balance. It is underpinning major investments in new liquefaction capacity despite low gas prices in both Europe and Asia. By 2040, China imports almost twice as much LNG as the next largest importing country, India, and the share of gas in China's energy mix rises from 7% today to 13% by 2040.
- The United States adds nearly 200 billion cubic metres (bcm) to global natural gas production by 2025, over half of which is destined for export. In the Stated Policies

Scenario, the United States produces more natural gas than the whole of the Middle East over the period to 2040. Iraq with mostly associated gas and Mozambique with vast new offshore discoveries emerge as large gas producers from a low base.

- LNG dominates growth in global gas trade. Technological and financial innovations are making LNG more accessible to a new generation of importers. The combination of a growing spot market and more destination flexibility are accelerating a move toward market-based pricing of LNG and away from oil-indexed pricing. In the Stated Policies Scenario, the share of "pure" oil-indexed import contracts in Asia declines from around 80% today to less than 20% in 2040.
- There is significant uncertainty as to the scale and durability of demand for imported LNG in developing markets around the world. LNG is a relatively high-cost fuel; investment in liquefaction, transportation and regasification adds a considerable premium to each delivered gas molecule. Competition from other fuels and technologies, whether in the form of coal or renewables, loom large in the backdrop of buyer sentiment and appetite to take volume or price risk.
- Associated gas – a by-product of oil production – reached 850 bcm in 2018, around 20% of the world's gas output. Globally, only 75% of this gas is used by the industry or brought to market. We estimate that 140 bcm was flared and 60 bcm released into the atmosphere in 2018, more than the annual LNG imports of Japan and China combined. This significant source of emissions represents 40% of the total indirect emissions from global oil supply.
- In 2018, on a lifecycle basis, natural gas resulted in 33% fewer carbon dioxide (CO_2) emissions on average than coal per unit of heat used in the industry and buildings sectors, and 50% fewer emissions than coal per unit of electricity generated. Coal-to-gas switching can therefore provide "quick wins" for global emissions reductions. Theoretically, up to 1.2 gigatonnes (Gt) of CO_2 could be avoided using existing infrastructure in the power sector. Doing so would bring down global power sector emissions by nearly 10%. With coal prices in 2019 in a $60-80 per tonne range, most of this potential would require gas prices below $4 per million British thermal units (MBtu). Such prices are below the long-run marginal cost of delivering gas for many of the world's suppliers, implying the need for additional policy support (in the form of carbon prices or regulatory intervention) to realise these emissions savings.
- Near-term efforts by member countries of the International Maritime Organization (IMO) to reduce sulfur emissions from shipping may provide a new market for LNG. The window of opportunity is relatively narrow and clouded by uncertainty about the lifecycle emissions intensity of LNG. The IMO long-term strategy envisages an overall emissions reduction of at least half by 2050, compared with 2008; in this case, the maximum amount of emissions that could come from ships using LNG in 2050 is estimated to be 290 million tonnes of CO_2.

Introduction

Natural gas had a remarkable year in 2018, with a 4.6% increase in consumption accounting for nearly half of the increase in global energy demand. In 2011, a *World Energy Outlook* (*WEO*) special report asked whether the world might be poised to enter a "Golden Age of Gas", based on supportive assumptions about gas availability and price, as well as policies on the demand side that could promote its use in certain countries, notably China (IEA, 2011). A few years on, global gas consumption is now very close to this 2011 projection. Since 2010, 80% of the growth has been concentrated in three key regions: United States, where the shale gas revolution is in full swing; China, where economic expansion and air quality concerns have underpinned rapid growth; and the Middle East, where gas is a gateway to economic diversification from oil. Liquefied natural gas (LNG) is the key to more broad-based growth; 2019 is already a record year for investment in new LNG supply, even as regional spot gas prices have fallen to record lows.

Natural gas continues to do far better than either coal or oil in both the Stated Policies Scenario (where gas demand grows by over a third) and the Sustainable Development Scenario (where gas demand grows modestly to 2030 before reverting to present levels by 2040). The stage appears to be set for natural gas to thrive, at least in relative terms, over the coming decades. However, the headline findings should not obscure some important commercial and environmental challenges facing the gas industry, as well as some major variations in the storyline in different parts of the world. We examine some of these uncertainties in three in-depth sections of this chapter:

- Market linkages between natural gas and oil are gradually loosening, at least when it comes to pricing arrangements. However, there are upstream ties between the fuels that will be much more difficult to undo. In this section, we examine the continued importance of gas produced as a by-product of oil – associated gas – in shaping market developments, drawing on case studies of the United States, Middle East and Brazil.
- The outlook for natural gas relies heavily on LNG as a way to connect regional markets and bring gas to new consumers, especially in fast-growing parts of Asia. In a world where innovation is bringing down costs in many areas, we ask how innovation might affect the outlook for LNG. We explore four issues: the costs of LNG supply; the way that LNG is contracted; its environmental credentials; and the potential for demand-side innovation to unlock new markets.
- We consider how natural gas contributes to energy transitions when it competes with, and substitutes for, more polluting fuels, in particular coal. Our analysis examines to what extent, and in which sectors and timeframes, this substitution reduces emissions compared with other policy approaches, and how the calculation changes when methane leaks are considered. It also highlights regional variations in the case for fuel switching and reflects on the role of natural gas in the Sustainable Development Scenario.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2019/secure/.

Scenarios

4.1 Overview

Table 4.1 ▹ Global gas demand, production and trade by scenario (bcm)

			Stated Policies		Sustainable Development		Current Policies	
	2000	2018	2030	2040	2030	2040	2030	2040
Power	908	1 571	1 708	1 936	1 580	1 248	1 823	2 197
Industrial use	644	909	1 229	1 474	1 108	1 114	1 243	1 527
Buildings	651	846	945	998	740	557	1 011	1 131
Transport	70	137	200	295	268	330	181	249
Other sectors	257	490	639	701	568	605	681	788
World natural gas demand	**2 530**	**3 952**	**4 720**	**5 404**	**4 264**	**3 854**	**4 940**	**5 891**
Asia Pacific share	*12%*	*21%*	*26%*	*28%*	*29%*	*34%*	*26%*	*28%*
Low-carbon gases	-	4	53	90	138	269	29	52
World total gases	**2 530**	**3 956**	**4 773**	**5 494**	**4 402**	**4 123**	**4 968**	**5 943**
Conventional gas	2 318	3 004	3 293	3 694	3 004	2 689	3 433	3 926
Existing fields	2 318	3 004	2 200	1 659	2 200	1 659	2 200	1 659
New fields	-	-	1 094	2 035	804	1 030	1 234	2 266
Tight gas	148	274	267	238	262	141	253	232
Shale gas	3	568	1 020	1 290	863	871	1 113	1 532
Coalbed methane	38	88	103	129	101	103	102	143
Other production	-	3	36	54	34	50	38	58
World natural gas production	**2 507**	**3 937**	**4 720**	**5 404**	**4 264**	**3 854**	**4 940**	**5 891**
Shale gas share	*0%*	*14%*	*22%*	*24%*	*20%*	*23%*	*23%*	*26%*
LNG	136	352	598	729	608	636	633	768
Pipeline	378	436	528	549	463	358	589	704
World natural gas trade	**514**	**788**	**1 126**	**1 278**	**1 071**	**993**	**1 222**	**1 472**
Share of production that is traded	*20%*	*20%*	*24%*	*24%*	*25%*	*26%*	*25%*	*25%*
Henry Hub price ($2018/MBtu)	**6.1**	**3.2**	**3.3**	**4.4**	**3.2**	**3.4**	**3.8**	**5.1**

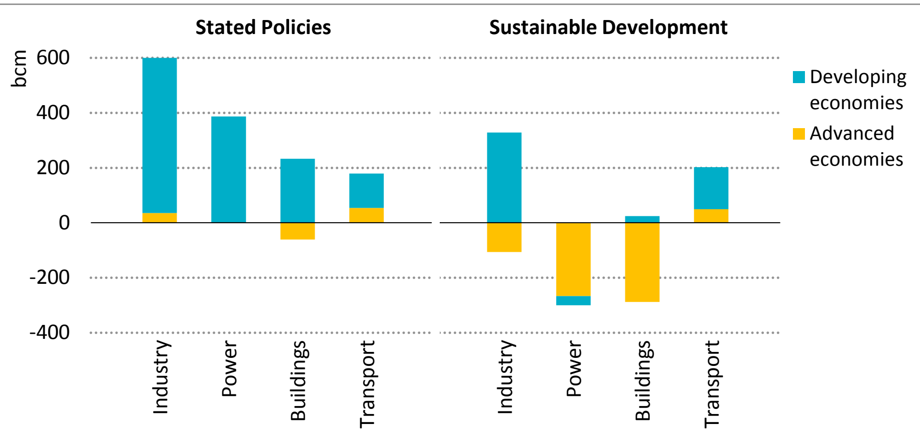
Notes: Low-carbon gases are biomethane and low-carbon hydrogen injected into the gas grid. Historical production and demand volumes differ due to stock changes. World trade reflects volumes traded between regions modelled in the *WEO* and therefore excludes intra-regional trade. See Annex C for definitions.

In the **Stated Policies Scenario**, overall global gas demand in 2040 is broadly similar to the level projected in the *World Energy Outlook-2018*, as a slight upward revision to the use of gas in industry compensates for a downward adjustment to gas consumption for electricity generation (IEA, 2018). Demand in the United States has edged higher, but this is offset by a sharper decline in the European Union, as well as by slightly slower projected growth in China. Production growth is dominated by shale gas, which grows at a rate of almost 4% each year, four-times faster than conventional gas. Natural gas prices have been revised down slightly: this is a consequence of lower oil prices, a larger shale gas resource base in the United States putting pressure on the Henry Hub price (which increasingly influences prices elsewhere), anticipated declines in the costs of LNG liquefaction and an acceleration in the move away from oil indexation.

In the **Current Policies Scenario,** higher overall demand for energy pushes up natural gas consumption: demand for gas in this scenario increases by 2 trillion cubic metres (tcm) by 2040, a level 50% higher than in 2018. In the absence of further support for renewables or efficiency policies, gas satisfies a third of total energy demand growth, and more than any other energy source. The Middle East, North America and Eurasia each provide a fifth of the total additional volumes required in this scenario, with around 45% of global incremental production consumed in developing Asian markets, primarily in China.

In the **Sustainable Development Scenario**, natural gas consumption increases over the next decade at an annual average rate of 0.9% before reaching a high point by the end of the 2020s. After this, accelerated deployment of renewables and energy efficiency measures, together with a pickup in production of biomethane and later of hydrogen, begins to reduce consumption (decarbonised gases are modelled in detail for the first time in this *World Energy Outlook*). By 2040, natural gas demand in advanced economies is lower than current levels in all sectors apart from transport, where demand remains broadly similar to the level reached in the Stated Policies Scenario. In developing economies, gas growth in the power sector rises to 2030 but falls back due to a growing share of renewables, while growth in industrial demand is around half the level of the Stated Policies Scenario (Figure 4.2). Although absolute consumption falls, natural gas gains market share at the expense of both coal and oil in sectors that are difficult to decarbonise, such as heavy-duty transport and the use of heat in industry. Even though natural gas-fired electricity generation declines, capacity grows compared with today as gas expands its role as a provider of power system flexibility.

Figure 4.2 ⊳ Change in gas demand by region and scenario, 2018-2040



In the Sustainable Development Scenario, advanced economies consume much less gas than today; in developing economies growth is more subdued, especially in power

4.2 Natural gas demand by region and sector

Table 4.2 ▷ Gas demand by region and scenario (bcm)

			Stated Policies				Sustainable Development	
	2000	2018	2025	2030	2035	2040	2030	2040
North America	800	1 067	1 163	1 183	1 195	1 221	1 052	791
United States	669	860	936	947	949	957	870	646
Central and South America	97	172	178	198	224	257	168	169
Brazil	10	36	34	37	46	57	30	40
Europe	606	607	621	593	578	557	519	380
European Union	487	480	477	442	416	386	387	266
Africa	58	158	185	221	265	317	176	200
South Africa	2	5	5	7	8	9	6	8
Middle East	186	535	559	646	739	807	550	507
Eurasia	471	598	628	639	652	674	551	471
Russia	388	485	505	506	506	514	438	363
Asia Pacific	313	815	1 071	1 218	1 374	1 522	1 234	1 322
China	28	282	454	533	598	655	508	497
India	28	62	103	131	166	196	199	303
Japan	81	120	102	90	90	89	92	62
Southeast Asia	89	163	203	231	264	295	212	240
International bunkers	-	0	11	21	34	50	14	15
World natural gas	**2 530**	**3 952**	**4 415**	**4 720**	**5 060**	**5 404**	**4 264**	**3 854**
World low-carbon gases	-	4	27	53	72	90	138	269
World total gases	**2 530**	**3 956**	**4 442**	**4 773**	**5 132**	**5 494**	**4 402**	**4 123**

In 2018, over 45% of the growth in the world's energy demand was met by natural gas, with rising consumption in the United States and China together accounting for 70% of the increase. Gas use also increased in some established markets such as Korea.

In the Stated Policies Scenario, natural gas demand reaches 5 400 billion cubic metres (bcm) in 2040, a level nearly 40% higher than today. There is broad-based growth across all sectors, with the share of gas in global primary energy demand increasing from 23% today to 25% by 2040. Gas overtakes coal by 2030 but trails oil (with a 28% share in 2040) in the global energy mix. In the Sustainable Development Scenario, the rapid fall in oil use means that gas becomes the main fuel in the global mix by the mid-2030s.

Industry accounts for almost half of the projected growth in natural gas use in the Stated Policies Scenario. Gas is increasingly used in steel making and petrochemical production (primarily fertilisers), as well as in a broad range of medium- and small-scale manufacturing (e.g. textiles, food processing, glass and ceramics). Gas is well suited to provide adjustable levels of process heat for industrial boilers and furnaces. Most of this growth occurs in developing economies, particularly in China, India and the Middle East.

In **electricity generation**, demand for natural gas differs by region. Several advanced economies, such as Europe and Japan, see a peak in gas use for power before the mid-2020s, after which demand flattens and in some cases falls below 2018 levels. In Europe, gas use in power rises to fill part of the gap left by declining nuclear and coal capacity, before falling in the second-half of the projection period as renewables continue to grow strongly. Japan lowers its gas consumption in power as nuclear plants gradually return to service and renewable capacity is added to the mix.

Projected growth in natural gas for power is more durable in several developing economies, where it increases by more than 350 bcm (a 40% increase over current levels) to meet strong electricity demand growth in parts of Asia as well as the Middle East and sub-Saharan Africa. However, gas is not the main challenger to coal in China or India, where its share in generation remains well below 10% in 2040. Overall, the share of gas in fossil fuel-based electricity generation globally rises from 35% in 2018 to 45% in 2040, while efficiency gains of 0.5% per year reduce average fuel requirements for gas-fired power plants by 11% compared to 2018.

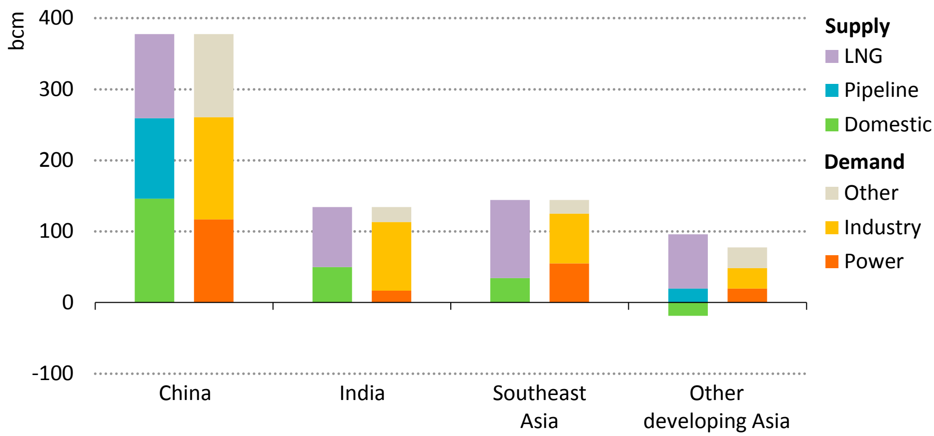
Compressed natural gas (CNG) and LNG both make inroads in the **transport** sector. CNG is primarily used for passenger vehicles while LNG enters markets for shipping and large road vehicles such as trucks and buses. Demand starts from a low base of around 140 bcm today, but grows to nearly 300 bcm by 2040, spurred by increased use in China and the United States, and to a lesser extent in India and the Middle East.

In the **buildings** sector, around 45% of the global net increase in natural gas demand is due to efforts to close the water supply gap in the Middle East through thermal desalination, which requires over 90 bcm of gas in 2040, primarily to provide drinking water. Much of the remaining growth comes from greater energy demand for cooking, where gas maintains an overall market share of around 40%. However, there is limited scope for gas to expand its role in providing residential heat, except in China. In advanced economies the use of gas for heating is curbed by improved efficiency, the direct use of renewables and increased electrification. This is particularly visible in the European Union, where overall gas demand in buildings declines by around two-thirds.

The **United States** remains by far the world's largest natural gas consumer. Underpinned by ample domestic supply, demand continues to grow strongly until the late-2020s before levelling off at around 950 bcm; the scope for large-scale switching in the power sector starts to dwindle, as does the scope for additional gas-intensive industrial development, while efficiency measures and electrification of heat in some parts of the country start to reduce demand in the buildings sector.

In **China**, natural gas demand more than doubles over the next two decades, rising by 370 bcm, more than the rest of developing Asia combined (Figure 4.3). There is an ongoing strong drive to use gas to reduce residential and industrial coal demand to improve air quality and reduce CO_2 emissions. Considerable potential remains: natural gas use currently accounts for 7% of total industrial energy demand compared with a global average of 22%, while only 12% of residential heating demand is met by gas in China. Although gas competes with electricity and the direct use of renewables in displacing coal in these sectors, its market share in industry and heat demand for buildings more than doubles over the period to 2040. By then, China consumes 650 bcm of gas, with the share of gas in the total energy mix reaching 13% (still well below the global average).

Figure 4.3 ⊳ Change in gas supply and demand in developing Asian markets in the Stated Policies Scenario, 2018-2040



In China, gas demand increases more than the rest of developing Asia combined and is supplied by LNG, pipelines and domestic production; LNG underpins growth elsewhere

In **India**, the prospects for natural gas are limited by supply constraints and affordability issues, as well as by the lack of infrastructure. Most of the projected growth in electricity demand is met by a combination of renewables (especially solar) and coal, with gas largely confined to a balancing role. Demand grows more quickly in other sectors, supported by efforts to expand the distribution grid to make gas more accessible to industry (including for new fertiliser plants), to households for cooking and water heating, and to new CNG infrastructure in urban areas. Overall gas consumption triples to nearly 200 bcm by 2040.

In **Southeast Asia**, coal and renewables are in a strong position to serve growing energy demand, but natural gas use also rises, nearly doubling to nearly 300 bcm by 2040 even as the region switches from a net exporter to a net importer of natural gas.

In **sub-Saharan Africa,** natural gas demand rises threefold; spurred by economic growth, expanding population and development of the large-scale gas resources discovered over the last decade (see Part B). Though the majority of production is exported, investments in domestic infrastructure stimulate demand across a broad range of industries as well as for household cooking.

4.3 Natural gas production

Table 4.3 ⊳ Natural gas production by region in the Stated Policies Scenario (bcm)

	2000	2018	2025	2030	2035	2040	2018-2040 Change	2018-2040 CAAGR
North America	763	1 083	1 254	1 336	1 358	1 376	293	1.1%
Canada	182	190	193	199	201	217	27	0.6%
Mexico	37	31	22	25	34	45	15	1.8%
United States	544	862	1 040	1 111	1 122	1 114	252	1.2%
Central and South America	102	177	188	209	244	285	108	2.2%
Argentina	41	45	58	78	101	126	81	4.8%
Brazil	7	26	28	37	55	75	49	5.0%
Europe	338	277	236	206	191	188	-89	-1.7%
European Union	265	120	66	47	44	40	-79	-4.8%
Norway	53	126	120	108	97	95	-31	-1.3%
Africa	124	240	287	372	435	508	268	3.5%
Algeria	82	96	96	104	112	125	29	1.2%
Egypt	18	59	81	92	95	98	39	2.3%
Mozambique	0	5	19	54	66	78	74	13.7%
Nigeria	12	44	41	45	56	65	22	1.8%
Middle East	198	645	721	787	912	1 016	371	2.1%
Iran	59	231	251	257	286	302	71	1.2%
Iraq	3	9	37	51	76	111	102	12.1%
Qatar	25	171	188	216	260	289	118	2.4%
Saudi Arabia	38	97	106	118	135	154	57	2.1%
Eurasia	691	918	1 021	1 054	1 105	1 143	224	1.0%
Azerbaijan	6	19	28	34	38	40	21	3.4%
Russia	573	715	797	798	834	853	138	0.8%
Turkmenistan	47	81	105	129	142	158	77	3.1%
Asia Pacific	290	598	708	757	816	889	291	1.8%
Australia	33	118	164	174	184	199	81	2.4%
China	27	160	224	250	274	306	146	3.0%
India	28	32	44	54	69	82	50	4.4%
Indonesia	70	72	75	79	85	95	22	1.2%
Rest of Southeast Asia	89	140	137	142	147	152	12	0.4%
World	**2 507**	**3 937**	**4 415**	**4 720**	**5 060**	**5 404**	**1 467**	**1.4%**
Sustainable Development			4 265	4 264	4 146	3 854	-83	-0.1%

Notes: CAAGR = compound average annual growth rate. See Annex C for definitions.

In the Stated Policies Scenario, natural gas production goes through two distinct phases. In the period to 2025, nearly 70% of the increase in global gas production comes from unconventional resources, largely driven by the continued ramping up of shale gas in the

United States, which is responsible for around 40% of total global gas production growth to 2025. Shale gas plays are found across the United States, but growth is primarily concentrated in the Marcellus and Utica shale plays, which together hold 17 tcm, or 40% of the country's total shale gas resources. Alone, these two plays are projected to add 200 bcm to total gas production in the United States over the next decade. The other major source of gas supply in the near term is associated gas from the Permian Basin.

The second period, from 2025-40, sees a shift in momentum back towards conventional natural gas, with accelerating production growth in the Middle East and several emerging exporters in sub-Saharan Africa. Meanwhile, shale gas production becomes more broad-based, as the peak in tight oil production in the United States contributes to a levelling off and subsequent decline in associated gas production. After 2025, 80% of growth in shale gas comes from outside the United States, primarily due to growth in Canada, Argentina and China, as well as smaller quantities in Australia, Algeria, Saudi Arabia and India.

Russia continues to be the second-largest natural gas producer after the United States, producing 850 bcm by 2040, a level nearly 20% higher than today. It also remains the largest gas exporter. The launch of the Bovanenkovo field in 2012 marked the start of a major new gas province in the Yamal Peninsula, which gradually becomes a mainstay for westward deliveries. The development of the Yamal and Arctic LNG projects underpins LNG export growth, while dramatic production growth in Eastern Siberia facilitates pipeline exports to China, initially via the Power of Siberia pipeline.

Qatar sees off competition from the United States and Australia to reclaim its position as the world's largest LNG exporter by the end of the projection period. An integrated LNG project to expand capacity by 45 bcm brings total liquefaction capacity above 150 bcm.

Mozambique sees the development of major offshore resources in the Rovuma Basin support a significant ramp up in LNG export capacity. The Golfinho and Atum fields within Area 1 block provide the feed gas for the recently approved 18 bcm LNG project (the largest in Africa), with further projects supported by the development of the adjacent Area 4. These projects enable Mozambique to overtake Nigeria in the late 2020s to become the largest gas producer in sub-Saharan Africa.

Iraq, barely in the top-fifty natural gas producers today, becomes the fastest-growing producer in the Middle East. Proven gas reserves stand at nearly 3.7 tcm, the majority of which is associated with oil. Two-thirds of the country's gas output, around 16 bcm, is currently flared, but capture rates increase and, as oil production expands to over 6 mb/d by 2040, additional associated gas is brought to market. As the political situation stabilises, particularly after 2030, the country sees a more than ten-fold increase in marketed production, from 9 bcm today to over 100 bcm by 2040.

Australia faces declining production from some mature basins, which brings some near-term challenges to maintain supplies for both domestic consumption growth and LNG exports. Over the long term, an additional 15 bcm of coalbed methane (CBM) is brought online by 2040, solidifying Australia's position as the world's largest CBM producer.

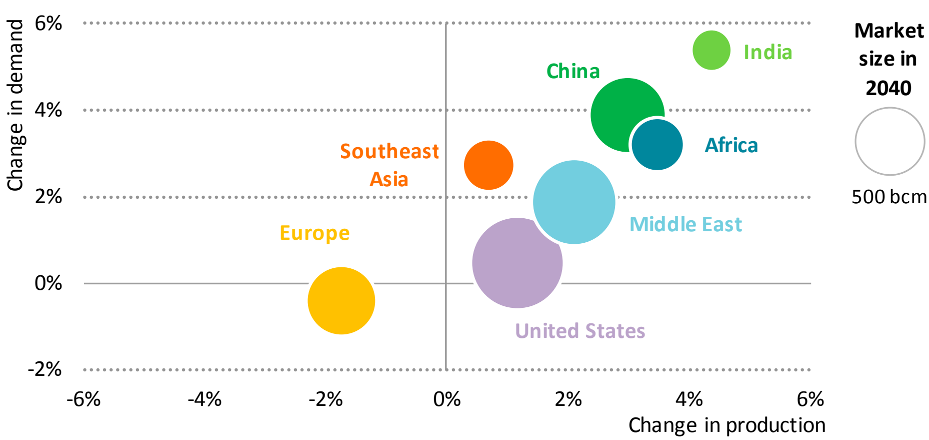
Although restrictions on gas development remain in place in some states, the lifting of a ban on hydraulic fracturing in the Northern Territories gives some impetus to shale gas exploration and eventual production, which increases to 30 bcm by 2040. In total, natural gas production reaches 200 bcm in 2040, a near doubling from today, but this relies on significant additional investment being unlocked by an alignment of state and federal hydrocarbon policies.

In **Europe,** natural gas production drops by 25% over the next decade, resulting in large part from the cessation of production at the earthquake-prone Groningen field in the Netherlands by 2022, and gradual resource depletion in the offshore North Sea. Norwegian production remains close to today's record highs before tailing off gradually. For Europe as a whole, marginal productivity gains from existing fields and some new offshore developments limit the decline in production to 90 bcm to 2040 (compared with a decline of 250 bcm – or 90% – if there were no further upstream investments).

4

Despite important shifts in the global gas trade balance, two-thirds of production growth over the projection period is consumed within each respective region. This results in a close relationship between the average annual change in production and the average annual change in demand (Figure 4.4).

Figure 4.4 ▷ Annual average change in gas demand and production in selected regions in the Stated Policies Scenario, 2018-2040



Domestic gas supply and demand growth remain interlinked

There are wide regional variations in the percentage of gas produced that is exported, with the range running from 20% in the United States to over 60% in sub-Saharan Africa. In some regions, countries increasingly require imports to satisfy demand growth, despite increases in production. China and India are the two prime examples: domestic output in both countries doubles, but consumption still runs ahead of production and therefore dependence on imports in both cases rises above 50% in the Stated Policies Scenario.

4.4 Trade[1] and investment

Table 4.4 ▷ Natural gas trade by region in the Stated Policies Scenario

Net importer in 2040	Net imports (bcm)				As a share of demand			
	2000	2018	2030	2040	2000	2018	2030	2040
European Union	221	360	400	356	46%	75%	89%	90%
China	1	122	286	353	5%	43%	53%	54%
Other Asia Pacific	-65	-27	88	181	n.a.	n.a.	24%	38%
Japan and Korea	97	170	145	153	97%	98%	99%	99%
India	-	30	78	115	-	48%	59%	58%
Other Europe	46	-29	-8	24	39%	n.a.	n.a.	14%
Net exporter in 2040	**Net exports (bcm)**				**As a share of production**			
	2000	2018	2030	2040	2000	2018	2030	2040
Russia	185	230	290	336	32%	32%	36%	39%
Middle East	12	109	138	203	6%	17%	18%	20%
North America	-37	16	150	149	n.a.	1%	11%	11%
Australia	10	78	126	148	31%	67%	73%	74%
Sub-Saharan Africa	5	36	97	133	33%	50%	62%	55%
Caspian	36	91	123	130	30%	45%	48%	45%
North Africa	61	45	53	57	57%	27%	25%	22%
Central and South America	5	5	10	26	5%	3%	5%	9%
World	**Trade (bcm)**				**As a share of production**			
	2000	2018	2030	2040	2000	2018	2030	2040
LNG	136	352	598	729	5%	9%	13%	13%
Pipeline	378	436	528	549	15%	11%	11%	10%
World	**514**	**788**	**1 126**	**1 278**	**20%**	**20%**	**24%**	**24%**
Sustainable Development			1 071	993			25%	26%

Notes: n.a. = not applicable. See Annex C for definitions.

In the Stated Policies Scenario, gas trade between regions expands by nearly 500 bcm, at an annual rate of around 2% through to 2040, running ahead of global gas demand growth. Imports continue to shift towards developing economies in Asia (Figure 4.5). China overtook Japan as the largest gas-importing country in 2018 and its imports are projected to reach the level of the entire European Union by 2040. China, India and other developing Asian markets account for most of the increase in global gas trade to 2040.

LNG emerges as the preferred way of moving gas over long distances, growing by more than 3% per year through to 2040. Pipeline gas increases at a more modest rate of 1% per year, with the increase primarily due to a tripling of China's pipeline imports; this offsets declines in net pipeline imports into the European Union in the latter half of the projection period, as the region takes higher volumes of LNG.

[1] Unless otherwise stated, trade figures in this chapter reflect volumes traded between regions modelled in the *WEO* and therefore exclude intra-regional trade.

The European Union's dependence on imported gas grows to nearly 90% by 2030 and the region retains a balancing role in global gas trade, thanks to a well-integrated gas market and a diversified mix of LNG, pipeline imports and storage infrastructure. Emerging importers on the other hand increasingly rely on the liquidity and responsiveness of the global LNG market to meet seasonal or short-term gas supply requirements (see section 4.6).

Russia and the Middle East retain their role as the largest gas exporting regions, but emerging exporters increase their market share. Australia briefly overtakes Qatar as the world's largest LNG exporter, while the United States becomes the second-largest gas exporter after Russia by 2025. Africa provides nearly 40% of export growth in the period 2025-40, primarily due to growing LNG exports from East Africa.

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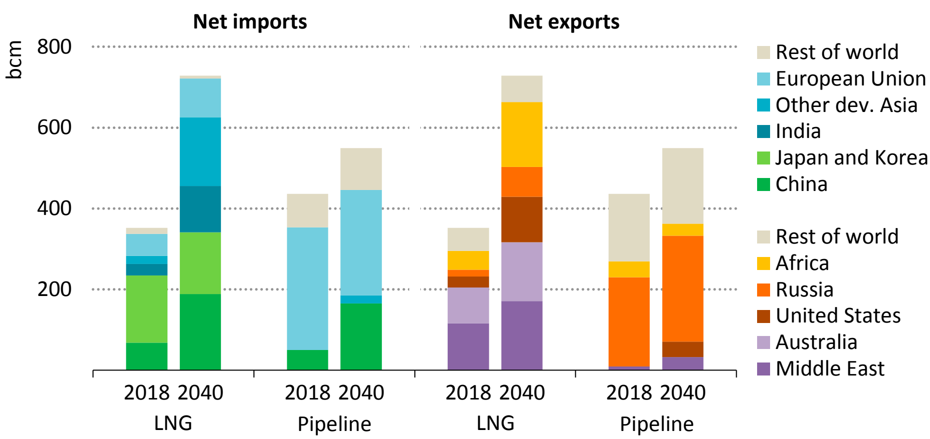
Figure 4.5 ▹ Natural gas net trade by region in the Stated Policies Scenario



LNG dominates the growth in global gas trade, with developing Asia its main recipient

Note: Other dev. Asia = other developing Asia.

In the Stated Policies Scenario, on average around $370 billion of annual investment in natural gas is needed between 2019 and 2040: $240 billion for developing upstream resources and $130 billion for infrastructure including transmission and distribution pipelines, shipping, and LNG liquefaction and regasification facilities. The last three years have seen comparatively low levels of gas upstream investment (IEA 2019a), but mid-stream investments are at a high level. Several major pipeline projects are nearing completion and 2019 is already a record year for new LNG liquefaction project approvals.

In the Sustainable Development Scenario, LNG trade remains robust through to the mid-2030s, in part due to increased imports in coal-intensive economies in developing Asia. Trade levels then start to reduce as overall gas demand begins to decline.

Key themes

4.5 Associated gas: the upstream link between oil and gas markets

Are natural gas and oil going separate ways? Spending on large-scale, capital-intensive LNG projects has been increasing. This is in contrast to the oil industry's focus on smaller, less complex short-cycle projects (IEA 2019a). Rising gas-on-gas competition is also challenging the rationale for oil indexation. However, because oil rarely rises to the surface without gas, the two fuels are unlikely ever to be completely delinked. Associated gas from oil fields is also the main source of flaring as well as a major source of gas that is vented directly to the atmosphere – both major sources of greenhouse gas (GHG) emissions – and it is important to understand the environmental footprint of this source of gas supply. This section examines the extent of global associated gas production and use, and explores in three cases how upstream linkages between oil and gas continue to affect the outlook for gas in the Middle East, the United States and Brazil.

Associated gas today

Most wells that are drilled to target oil formations also yield a mixture of other hydrocarbons such as condensates, natural gas liquids and natural gas. The latter is known as "associated gas". In essence, associated gas comes as a by-product from an oil well or field and non-associated gas comes from a well or field that is primarily geared for gas production.[2]

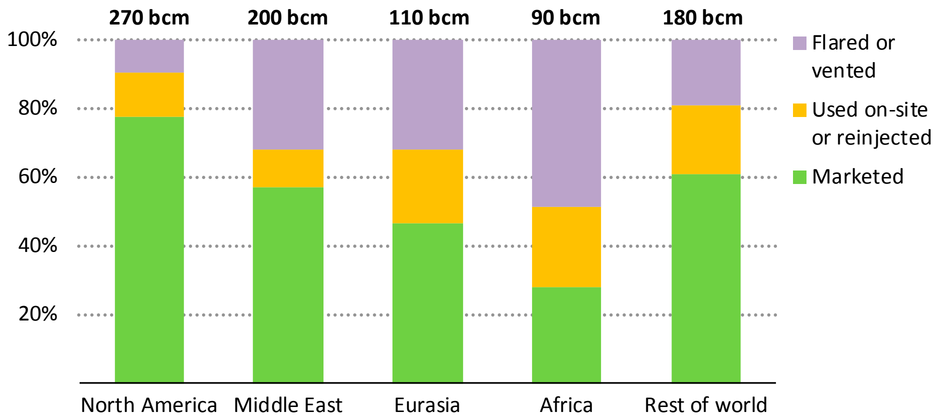
Associated gas has often been seen as an inconvenient by-product of oil production: it is generally less valuable than oil per unit of output and is costlier to transport and store. It is often used on-site as a source of power or heat. It can also be reinjected into oil wells to create pressure for secondary liquids recovery (as is common, for example, in Norway, Iran and Venezuela). Under the right geological conditions, it can also be stored and sold to the market at a later stage. Associated gas is usually collected via a network of gathering pipelines for further processing or direct injection into gas grids. When the gas is rich in natural gas liquids (NGLs), extra processing is required to separate out the heavier hydrocarbons such as ethane, butane and propane.

When there is no on-site use for the gas and a lack of infrastructure prevents it from reaching nearby markets, it is vented or flared. Associated gas can also be unintentionally released to the atmosphere as fugitive methane emissions. Together, such non-productive uses of gas have significant environmental consequences, making up around 40% of the indirect emissions associated with oil production. They also represent a wasted economic

[2] There is no single definition of the boundary between associated and non-associated gas. Here, if the amount of gas is more than 60% of the hydrocarbons extracted in energy terms (or around 250 cubic metres per barrel of oil), it is classified as a gas well that produces non-associated gas; otherwise it is classified as an oil well that also produces associated gas. Changing this to 50% would reclassify around 30 bcm from associated to non-associated gas.

opportunity: the 200 bcm that was flared (140 bcm) or escaped into the atmosphere or vented (60 bcm) in 2018 was greater than the annual LNG imports of Japan and China combined. Globally, only 75% of associated gas is used or brought to market (Figure 4.6).

Figure 4.6 ▷ Use of associated gas by region, 2018

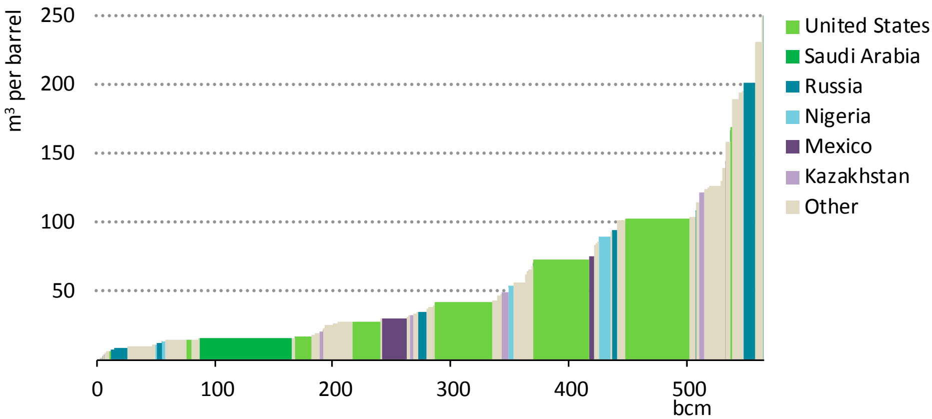


Only 75% of associated gas is put to productive use; flaring and venting is more common in remote areas of production which often lack nearby markets

While gas is often flared temporarily while operators test equipment and undergo pre-commissioning works or for safety reasons, "routine" flaring occurs when there is a failure to put associated gas to productive use. This may be because of the remoteness of fields or the topography of the surrounding area or because the local price of gas discourages operators from developing costly gas transportation infrastructure to reach existing or potential new markets. Associated gas also often comes with a combination of water vapour, hydrogen sulphide, nitrogen or carbon dioxide, and the cost of separating out these unwanted elements may be higher than the potential profits from the gas. Although several countries have imposed regulatory measures to restrict flaring, these are often inadequately enforced. Even in countries with well-developed gas markets, such as the United States, around 10% of associated gas extracted today is flared or vented.

The United States is the largest producer of associated gas, accounting for over a third of the global total, nearly equal to the next five countries combined. In most countries, associated gas constitutes less than a fifth of total marketed gas production, but in some large oil and gas-producing countries, such as Mexico, Saudi Arabia, Brazil and Nigeria, it makes up a much larger share. On average, gas makes up around 10% of the energy content of an oil field, but this is subject to wide variation depending on geological conditions, well design and production method (Figure 4.7).

Figure 4.7 ▷ Associated gas volumes in the total output from oil fields, 2018



On average, every barrel of oil produced today comes with around 60 cubic metres of gas, but this is subject to wide variations across the world's oil- and gas-producing regions

Middle East

The Middle East holds nearly 40% of global proven gas reserves, but these are not spread evenly across the region. In the two largest gas-producing countries, Iran and Qatar, natural gas and condensate resources have been developed independently of oil. However, more than 80% of the gas in Saudi Arabia and Kuwait is associated gas, and there are also significant volumes in Iraq and Oman. Associated gas has underpinned the rise of gas demand in many of these countries since it has largely been available at close to zero cost as a by-product of oil production. It has also provided a basis for economic diversification away from oil.

In recent years, associated gas production in the Middle East has struggled to keep pace with soaring domestic demand, which has tripled since 2000. Gas has been used as a substitute for oil in the power sector in producer countries because it frees up additional volumes of crude for export. It has also become a crucial fuel for water desalination plants. However, these end-uses cause significant peaks in consumption in summer months and, in the absence of significant storage capacity, associated gas has struggled to accommodate this seasonal variability. Unable to keep pace with demand, Kuwait and the United Arab Emirates have resorted to seasonal LNG imports, while Oman has had to cut back LNG exports to redirect supply to the domestic market.

The shortfall in associated gas, combined with the soaring pace of gas demand, has driven several oil-rich countries to develop non-associated gas fields, particularly those containing NGLs. Since 2000, the Middle East has seen a fourfold growth in non-associated gas production. This has supported the development of new gas value chains and has underpinned Qatar's rise to become the world's largest LNG exporter (helped by the liquids-rich North Field). It has also led to integrated gas and NGL projects in the United Arab Emirates and Saudi Arabia that have spurred the development of heavy industries and petrochemical complexes.

Some countries are facing a need to raise gas prices to support further upstream development of more complex non-associated gas projects. They face a delicate balancing act on price given their overall macroeconomic reliance on low-cost gas supply. The Saudi government is planning a pricing regime that differentiates associated from non-associated gas to reflect the higher development cost of non-associated gas. End-user prices for non-associated gas are likely to be between $1.5-3.9/MBtu, compared with less than $0.50/MBtu for associated gas (Saudi Aramco, 2019). Even prices at the higher end of this range are unlikely to cover the long-run production costs of these resources, which are located in difficult-to-develop fields. The Saudi Arabian government has also granted tax and fiscal incentives to Saudi Aramco for gas production, a sign of the priority assigned to domestic gas development. Oman, Bahrain and the United Arab Emirates have put similar measures in place.

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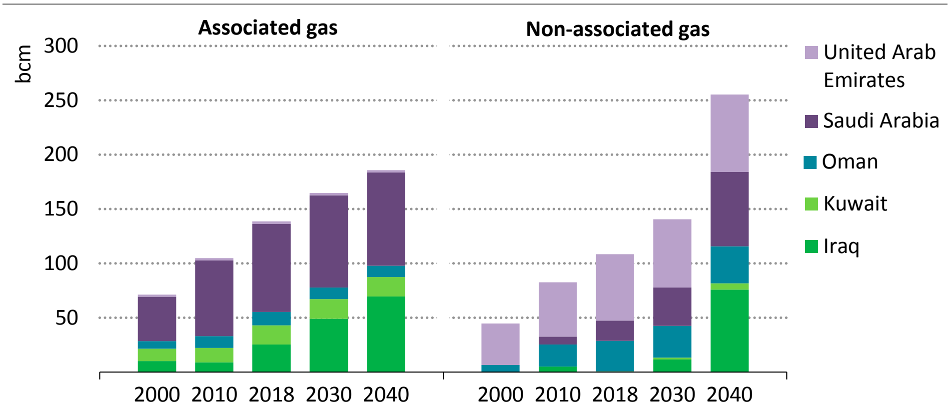
Figure 4.8 ▷ Associated and non-associated gas production in selected countries in the Middle East in the Stated Policies Scenario



Several Middle Eastern countries are diversifying into non-associated gas fields to support further development of domestic gas markets

Note: Associated gas volumes include flaring.

In the Stated Policies Scenario, several countries in the Persian Gulf squeeze some marginal gains out of existing associated gas production, as oil output grows by 3.9 million barrels per day (mb/d) over the period to 2040. However, the majority of growth comes from non-associated gas resources, with production nearly doubling to reach 250 bcm by 2040 in the countries in Figure 4.8. Saudi Arabia, for example, derives most of its incremental production from non-associated gas, which allows the country more or less to keep pace with demand growth in the power, petrochemical and desalination sectors. The main exception is Iraq, which is a relative latecomer in the development of its non-associated gas resources. In the medium-term, most of its gas production growth comes in the form of associated gas from a ramp up in oil production and a reduction in the rate of flaring, allowing it to meet significant latent demand for electricity generation and removing the need to import gas from Iran.

Overall, natural gas's share of total marketed oil and gas production in the region rises from 26% today to nearly 33% by 2040. The brisk pace of non-associated gas production allows the Middle East to develop upstream oil and gas supply chains that are increasingly separate from each other. It also accelerates the displacement of oil in electricity generation. At the same time, oil and gas remain tied together by continued investment in large-scale petrochemical and refining complexes in several parts of the Middle East, since these require an integrated hydrocarbon processing chain consisting of gas, oil and NGL feedstocks. Looking ahead, the development of non-associated gas has important implications for the region's ability to adapt to the demands of the Sustainable Development Scenario, where oil production begins to decline very soon while gas demand continues to grow until 2030. The divergent paths in this scenario raise questions about how investment is divided between associated and non-associated gas, and about how countries in the Middle East reconcile declining crude oil exports with continued robust growth in domestic gas demand.

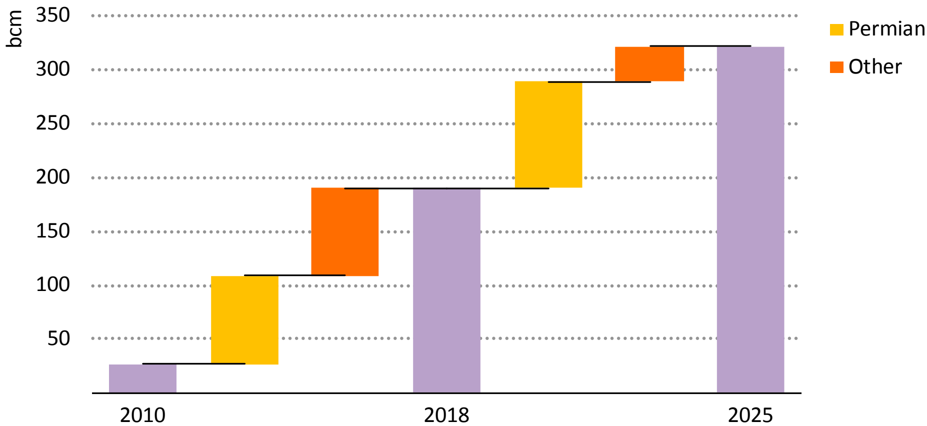
United States

Associated gas production in the United States has doubled over the last decade, reaching nearly 200 bcm in 2018. It accounts for around 20% of the gas produced in the United States today.

More than half of associated gas production comes from tight oil plays and significant further growth is expected (Figure 4.9). The Bakken formation in North Dakota and the Eagle Ford play in Texas, developed in the early 2010s, were the first basins to yield significant quantities of both gas and oil from horizontal drilling. Since 2017, the Permian Basin in southwest Texas has been the main source of growth reflecting a huge ramp up in drilling activity and major productivity gains that have increased the amount of oil and associated gas output per well (see Chapter 3). As drilling has increased, so have estimates of remaining technically recoverable resources: the Permian is now estimated to hold nearly 7 tcm of gas, alongside 80 billion barrels of oil.

Drilling in the Permian primarily targets more valuable liquids; gas is essentially a very low-cost by-product of this activity. This has created a number of dilemmas for US producers. While crude oil can be transported by road or rail, associated gas must be transported through dedicated pipelines; the strong production growth seen over the past three years has outpaced mid-stream processing and pipeline transport capacity, creating bottlenecks that have put strains on upstream operations. Companies have responded by leaving drilled wells uncompleted and selling off associated gas at very low, and at times even negative, prices. They have also increased the amount of flaring; in the Permian alone, levels of flaring have risen more than twenty-fold since 2011, when total flared volumes were estimated at 250 million cubic metres. Recent data suggest that as much as 7 bcm could be flared in the Permian in 2019 (Oil and Gas Journal, 2019). As earlier experience in the Bakken formation showed (where as much as 30% of extracted gas was flared in the early 2010s, and where levels have come down only slightly since), flaring on this scale invites a regulatory response and is extremely damaging to the reputation of the upstream industry at a time when there is ever-increasing scrutiny of its environmental performance.

Figure 4.9 ▷ Associated gas production in the United States in the Stated Policies Scenario, 2010-2025



The Permian Basin accounted for nearly half of associated gas production in 2018

Constraints on pipeline capacity to transport associated gas away from where it is extracted are visible in widening price differentials between associated gas-producing basins and the Henry Hub benchmark. These differentials send a clear economic signal about the case for investment in new connecting pipelines, but the scale of projected associated gas production growth in the Permian in the Stated Policies Scenario would require a doubling of take-away capacity (currently around 100 bcm) by 2025.

It is not clear which demand centres have the greatest capacity to absorb this low-cost gas. Pipeline exports to Mexico have increased more than fourfold since 2010, but the prospects for exporting additional quantities are limited by the need for further development of pipeline infrastructure within Mexico, as well as by Mexico's own gas production prospects. In the Stated Policies Scenario, exports to Mexico rise modestly to just above 55 bcm by 2025. There is some potential for gas demand growth in the power sector in the southern parts of the United States, as coal-fired capacity is increasingly retired, but this is tempered by expanding deployment of wind and solar capacity. Switching all coal-fired electricity generation that remains in the region in the Stated Policies Scenario in 2025 to natural gas would require an additional 30 bcm. Taken together, additional exports to Mexico and further coal-to-gas switching would only absorb around 40% of the growth in associated gas from the Permian Basin.

LNG export terminals are expected to be the main outlet for associated gas. Around 80% of liquefaction terminal capacity in operation in the United States today is on the coast of the Gulf of Mexico. New pipelines that link low-cost Permian gas to these export facilities, such as the recently completed 20 bcm Gulf Coast Express, have a critical role to play in relieving the pressure on upstream producers by providing a route to market for their associated gas. Several proposed LNG export projects have made sourcing lower cost gas from the Permian a key part of their business model, which means that new pipelines will also help support the commercial case for the next wave of US LNG export expansion.

The implications of a possible rise in oil prices are likely to reinforce the desire of producers to send associated gas to LNG terminals for export. Any increase in the oil price would be likely to stimulate additional tight oil production, which would lead to more low-cost associated gas, thereby putting downward pressure on domestic gas prices. At the same time, higher oil prices would increase oil-indexed LNG prices, enhancing the competitiveness of Henry Hub linked LNG exported from the United States. A $20/barrel increase in the oil price compared with our projection in 2025 would push tight oil production in the United States up by 0.6 mb/d. This, in turn, would increase associated gas production by 10 bcm, pushing higher volumes of lower cost gas to LNG export terminals.

Brazil

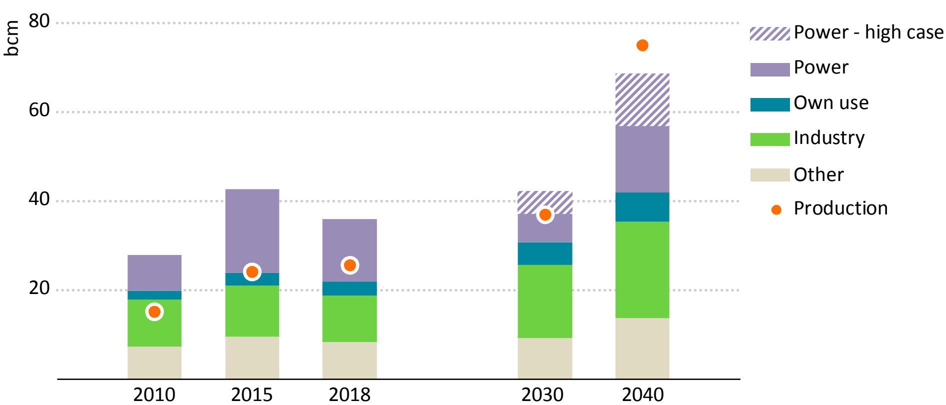
Associated gas has a crucial place in the future energy mix of Brazil. The development of offshore pre-salt fields has led to increasing quantities of associated gas production. Today, every barrel of oil extracted from pre-salt fields is accompanied on average by 20 cubic metres of gas, which means that associated gas accounts for around 10% of total output in energy terms. In the Stated Policies Scenario, offshore gas production rises from 21 bcm today to over 60 bcm by 2040.

Despite growing production from this significant resource base, Brazil today relies in part on imports to meet its domestic gas demand. It could potentially make much more use of its own gas, but it lacks the necessary pipeline infrastructure. Pipeline capacity is sufficient to bring onshore around 8.5 bcm of associated gas, while gross production is running at around 32 bcm. Producers reinject over a third of the associated gas into the pre-salt fields and flare the remaining 3%.

There is also a mismatch between associated gas supply and demand. Gas demand for electricity generation varies considerably from one year to the next in Brazil because gas is used to balance the annual availability of large-scale hydropower. As a result, gas demand for power over the last decade has varied from as little as 3 bcm to nearly 20 bcm (Figure 4.10). This means that producers of associated gas do not at present have a relatively constant source of demand to justify building additional pipeline capacity to bring gas onshore. Significant storage capacity could potentially provide such a constant source of demand, but it would be difficult to obtain finance for this precisely because of the annual unpredictability of gas demand. New power projects linked to associated gas that would typically run as baseload supply could also potentially provide a stable source of demand. Currently, however, Brazil's power market is oversupplied, meaning that the delivered cost of associated gas to such power projects would need to be low enough to justify new investment in plants that need to run as baseload. Meanwhile expanding wind and solar capacity adds a further challenge to the investment case.

As oil and associated gas output grows, the question of how best to market the gas beyond the power sector becomes more pressing. Industry may provide the relatively constant year-round demand required by associated gas production, but demand growth in industry may not keep pace with the expected growth in gas production. Petrobras, Brazil's oil and gas incumbent company, is exploring other technologies that potentially avoid the need for costly offshore-to-onshore pipeline infrastructure, such as floating LNG, gas-to-liquids processes or CNG for the transport sector. It is not yet clear whether these technologies represent cost-effective alternatives to conventional infrastructure.

Figure 4.10 ▷ Natural gas demand and production in Brazil in the Stated Policies Scenario



Hydropower variability influences Brazil's annual need for natural gas; associated gas production creates new challenges for balancing supply with this variable demand

Note: "Power - high case" illustrates the additional gas demand if gas-fired power plants ran at higher load factors in order to compensate for reduced hydro availability.

In the Stated Policies Scenario, Brazil continues to import gas on a flexible, short-term basis to complement the variability of its hydro generation. Some baseload gas demand for power is met by associated gas, but the main source of growth is demand for industry, at a rate of 3.4% per year to 2040. Supply still runs ahead of demand, and so we anticipate the development of LNG export capabilities by the end of the next decade.

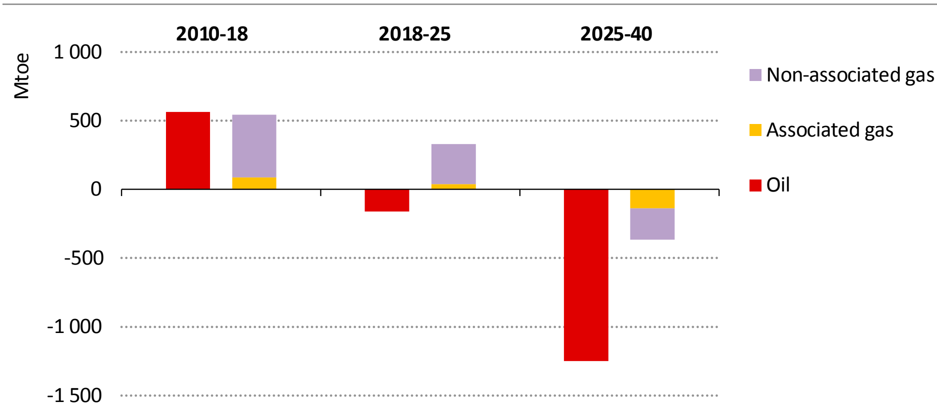
Outlook for associated gas

These case studies suggest that the key hurdles to finding markets for associated gas are the need to build additional infrastructure and the need to match a stable supply of output with demand in situations where many sources of demand are variable. In most parts of the world, in the absence of determined action by regulators, operators have greater incentives to flare associated gas than to curb more valuable oil output.

In the Stated Policies Scenario, efforts to reduce this practice bear fruit, with flaring rates declining by half even as oil production increases. The United States dominates the rise in associated gas over the next decade, accounting for 75% of total growth. Production becomes more evenly distributed after 2030, reflecting a greater diversity in oil supply during this period. Associated gas increases from 565 bcm to 680 bcm by 2040, but its share of total marketed gas production drops to 13%, as global oil demand levels off while natural gas demand continues to rise.

In the Sustainable Development Scenario, flaring rates decline faster (as do methane emissions) and the share of total gas output accounted for by associated gas drops more quickly. Global demand for crude oil declines in the early 2020s, while demand for gas continues to rise throughout most of the rest of the decade; demand for natural gas then falls away more slowly than demand for oil (Figure 4.11). The divergent trajectories in this scenario create a variety of challenges for operators: in a world of reduced revenue from oil, they face an even stronger imperative to invest in gas capture, and minimise flaring and venting. Some emerging technologies, such as small-scale LNG, may offer a commercially viable alternative to the reduction of flaring and venting of associated gas.

Figure 4.11 ▷ Change in global gas and oil production in the Sustainable Development Scenario



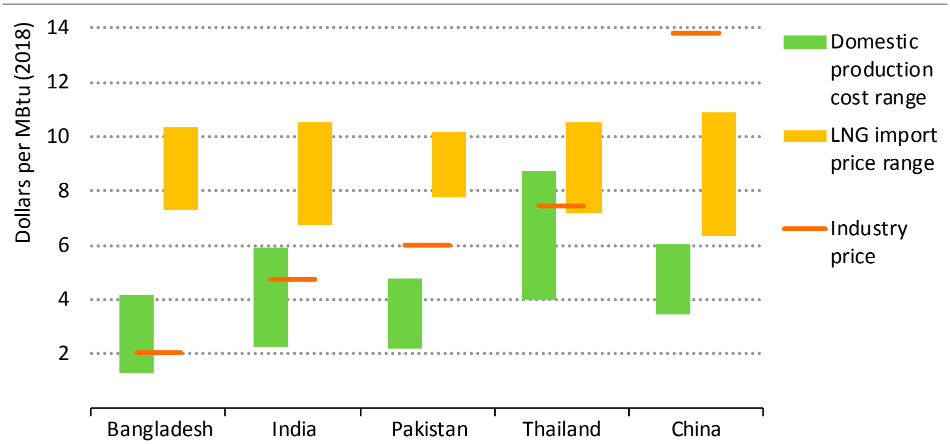
In the Sustainable Development Scenario, falling demand for oil reduces associated gas production, while increasing pressure on operators to ensure its productive use

4.6 How does innovation affect the outlook for LNG?

In the Stated Policies Scenario, LNG overtakes pipeline gas as the main way of trading gas over long distances by the late 2020s. Developing economies in Asia are the main engines of LNG growth, with the market share of LNG in total gas demand growing from 20% in 2018 to 40% by 2040.

There is significant uncertainty, however, as to the scale and the durability of demand for imported LNG in developing markets around the world. The price sensitivity of demand is one key uncertainty: another is the extent of competition from other fuels and technologies, whether in the form of coal or renewables. LNG is a relatively high-cost fuel, with investment in liquefaction, transportation and regasification adding significantly to the cost of the gas itself. As shown in Figure 4.12, emerging markets in Asia are facing significantly higher costs for imports than for domestically produced gas. Even though spot gas prices fell to record lows in 2019 on the back of ample LNG supplies, over the long-term end-user prices generally seem set to rise: unless they do, LNG suppliers will be unable to recover their long-term investment costs or governments will have to continue to subsidise the cost of LNG imports. The LNG industry faces a struggle to gain a strong foothold in developing markets where affordability is a key consideration.

Figure 4.12 ▷ Domestic natural gas production costs, LNG import prices and industry gas prices in developing Asian import markets, 2018



End-user prices are generally high enough to sustain domestic production in developing Asian gas markets, but below the costs of imported LNG in several markets

Note: LNG import price ranges are based on data from Argus Media (2019).

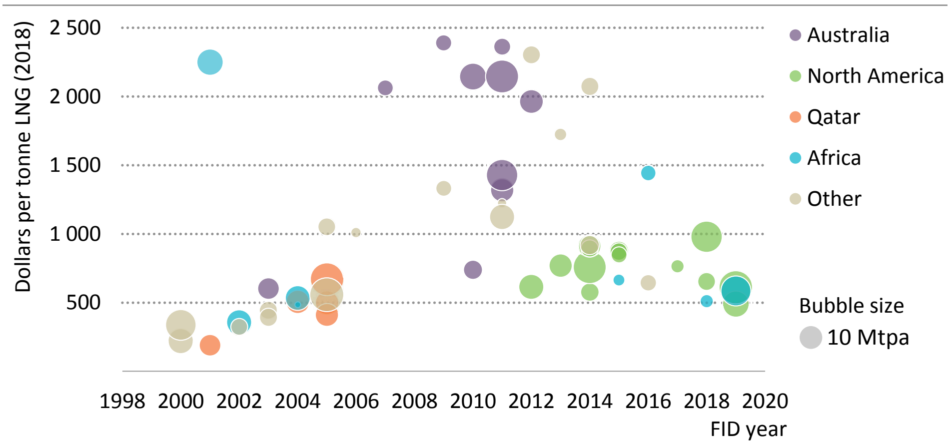
LNG has compensating advantages that have the potential to justify its premium price. It can be provided flexibly and relatively quickly, which are helpful qualities from the point of view of energy security. In some cases LNG also has a competitive advantage over oil. In addition, although LNG supply chains tend to produce more emissions per unit of gas than pipeline gas because of the additional energy requirements for liquefaction, LNG still has significant environmental benefits when it substitutes for more polluting fuels such as coal or oil (see section 4.7). The limited air pollutants emitted by natural gas make it particularly attractive for developing economies concerned about air quality. Policy support for building gas infrastructure and tapping into LNG supply, including through small-scale infrastructure, has been a critical part of its evolution.

The business model for buying and selling LNG is changing. As gas-on-gas competition increases, fewer LNG export projects are likely to be able to rely in the future on a return on investment by delivering volumes under fixed oil-indexed long-term contracts with re-export restrictions and take-or-pay conditions. Sellers will therefore have to innovate to attract new buyers. Technology is opening new opportunities to supply LNG directly to various end-use sectors, notably transport. We examine how innovation in the LNG supply chain affects the outlook for liquefaction costs, contracting patterns, environmental performance and demand-side technologies.

Where are liquefaction costs heading?

Liquefaction is the most capital-intensive part of the LNG supply chain, in most cases accounting for nearly 50% of the delivered cost of gas. While there are common elements, the costs of liquefaction terminals are dictated ultimately by project-specific factors, such as their location, size and complexity.

Figure 4.13 ▷ Capital costs of liquefaction projects



Liquefaction costs have come down from their pre-2014 highs

Note: Mtpa = million tonnes per annum; FID = final investment decision.

The evolution of LNG liquefaction costs since 2000 can be separated into three phases (Figure 4.13). At the start of the century investment costs of below $500/tonne were achieved at a number of projects through competitive bidding by engineering, procurement and construction companies and an increased focus on cost. Size also matters, as demonstrated in the case of Qatar, where efforts to develop integrated projects using the world's largest LNG trains yielded important economies of scale. With the rise in oil prices and the move toward more remote, technically complex sites over the 2008-12 period, liquefaction costs began to escalate beyond $2 000/tonne. Most of these high-cost projects were built in Australia, where investment decisions were compressed into a relatively short space of time (and in the case of projects in Queensland, a relatively small geographical area). This created labour and service bottlenecks as well as higher material costs, which were compounded by a strong local currency. Since 2014, around two-thirds of investment in new liquefaction has been made in the United States, where projects were primarily based on converting regasification terminals. With some of the necessary infrastructure already in place, a large and competitive LNG construction industry, and declining oil prices, costs have reverted to the previous range of $500-1 000/tonne.

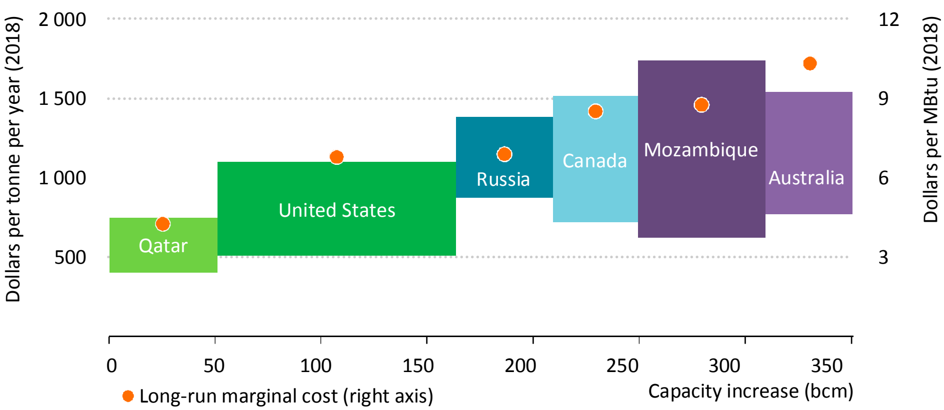
Due to the scale, location and complexity of its projects, the LNG industry has found it difficult to deliver projects on time and on budget. Cost overruns and delays in the period between 2009-14 were particularly common, with over half of projects sanctioned experiencing delays of a year or more or exceeding the budget estimates made at the time when the final investment decision was taken. Delays appear to have continued since 2014: out of 22 projects that have come online, 11 have seen significant delays in commissioning dates.

Despite these downside risks, LNG remains one of the few parts of the oil and gas sector that has continued to see traditional large-scale, capital-intensive infrastructure projects. After a three-year lull in project approvals, the market for new liquefaction capacity appears to have turned a corner, with 2019 seeing a record number of project approvals. There is a long list of competing projects around the world that are seeking to advance towards a final investment decision. A number of brownfield projects are also being pursued. These are additions to existing facilities that can tie in to new nearby gas resources, while making use of existing infrastructure and drawing on established operational knowledge and relationships with contractors. Some existing LNG export facilities also seem set to undergo "debottlenecking" to optimise plant facilities and squeeze out additional capacity.

In addition to the "brownfield advantage", there are several emerging business model innovations that have important implications for costs. In the United States, a supportive regulatory environment and an unbundled, competitive gas industry has helped to reduce the weighted average cost of capital for new projects (Box 4.1). Some projects – particularly in North America – are also phasing in the development of large-scale liquefaction terminals, by using mid-scale train sizes of around 1-2 million tonnes per annum (Mtpa). This kind of project structure theoretically requires lower upfront capital and hence makes financing more accessible. It also allows for the monetisation of gas resources incrementally and can be coupled with a modular design, whereby standardised equipment and prefabricated liquefaction modules are built off-location and delivered when complete.

There are several design configurations available for modular, mid-scale projects and increasing competition between nearly a dozen major vendors. In some cases, projects have also benefited from concessionary tax breaks provided by governments keen to encourage the significant capital inflows brought by these large-scale projects.

Figure 4.14 ▷ Investment cost ranges for liquefaction capacity and long-run marginal costs in the Stated Policies Scenario, 2018-2040



There is a wide range of investment costs for liquefying gas; along with feed gas and shipping costs, LNG project economics set the marginal price of gas in several markets

Notes: Long-run marginal costs equal the weighted average costs in each country of developing gas resources, building liquefaction terminals and shipping the total LNG volumes delivered over the projection period. Shipping costs reflect the volume-weighted average cost of delivery to importing regions in the Stated Policies Scenario. Assumed asset lifetime is 30-years with a cost of capital in the range of 5-10%.

In the Stated Policies Scenario, the costs of liquefaction are maintained in a relatively wide range of $400-1 200/tonne per year, with some projects exceeding the upper value towards the end of the projection period. Around 430 bcm of liquefaction capacity is developed at a total investment cost exceeding $300 billion, with 80% of total capacity being built in just six countries (Figure 4.14). Ultimately, gas prices rise to meet long-run production costs. Taking into account the cost of feed gas, liquefaction costs and shipping costs to regasification facilities, this scenario sees a weighted average long-run marginal cost of LNG of $7.50/MBtu over the projection period, with marginal projects exceeding $10/MBtu by 2040. This projection takes into account different types of projects and designs, but does not build in any cyclical element to the market for new LNG infrastructure. It assumes that the industry shows strong discipline on costs and project management. Given the competitive pressures facing LNG, there is very little margin to absorb cyclical upswings in costs or cost overruns.

Box 4.1 ▹ Innovation in LNG financing and marketing strategies

LNG projects are among the most capital-intensive in the energy world. Sponsors have typically relied on project finance to raise the necessary funds to build liquefaction capacity and procure dedicated upstream feed gas. This type of finance involves securing loans from banks and other large lenders such as export credit agencies, backed by long-term contractual commitments from large creditworthy buyers, which agree to a minimal offtake of LNG with re-export restrictions and take-or-pay conditions. Final investment decisions are typically made when at least 80% of the proposed output from an LNG terminal is contracted to long-term buyers. The lenders are paid back from the cash flows generated by the project.

This business model has been in place for decades, but it has come under threat from the emergence of new LNG suppliers and market participants, especially in the United States. Projects there were built under either tolling or merchant models, without dedicated upstream supplies or downstream transport assets. Project finance was secured by having buyers sign up to long-term capacity rights at the terminal (whether it is used or not). Much of the gas has been sold to portfolio players, who take ownership of LNG at the liquefaction facility and are free to deliver it to a diverse set of buyers through a combination of spot transactions and short- and long-term contracts. Such models have unlocked bigger volumes of destination-flexible LNG supply.

Growing confidence in an LNG spot market has encouraged large players to move away from project finance and toward balance sheet financing, which involves using retained earnings as well as raising debt or equity on the strength of a project sponsor's own creditworthiness. This route is essentially only open to international oil companies and national oil companies with significant financial resources. It implies higher financing costs and involves higher market risk, as it means fewer guarantees from long-term buyers and more exposure to global gas price volatility, but it offers the potential to capture larger returns. LNG Canada, Golden Pass in the United States and the Tortue floating LNG project off the cost of Mauritania and Senegal are examples of recently approved projects that combine balance sheet financing with a portfolio marketing model. The risks involved in balance sheet financing can be managed, for example by entering into joint ventures or shifting some of the construction risk onto engineering contractors through lump sum turnkey contracts. Some projects in the United States are testing new models of risk allocation by offering prospective partners equity stakes in the liquefaction terminal itself.

Balance sheet financing implies that greater amounts of the volumes from LNG terminals are bought by intermediaries rather than end-users, thereby increasing market liquidity. However, it is not yet clear how it might impact the delivered cost of LNG. We estimate that decreasing the cost of financing by half could decrease the delivered cost of LNG by up to 10%. However, this decrease may be offset by the need for higher risk-adjusted returns. In the Stated Policies Scenario, $14 billion on average is spent every year on new LNG capacity to 2040. Although this scenario sees changing financing patterns, long-term contracts that commit buyers to significant deliveries of gas remain an important element in the approval of new projects.

Growth in contractual innovation

Over the last decade, the number of companies purchasing LNG jumped from 40 to nearly 100, with total contracted volumes more than doubling to 360 Mtpa. Fifteen new LNG buyers have emerged in the last two years alone, a reflection of the growing supply and accessibility of LNG. In this more crowded marketplace, LNG contracts are becoming much more diverse and the terms of trade between buyers and sellers are evolving.

The changes underway are partly a consequence of utility buyers in both established and emerging markets no longer being certain of their long-term gas requirements. Their investment horizons have been clouded by the declining costs and rising deployment of renewable energy sources, and in some cases by increased competition from market opening. New LNG buyers in developing markets tend to have a different risk profile and to be more willing to contract gas on a more speculative basis. At the same time, a growing secondary market for LNG has given buyers more confidence in the short-term availability of supply. Together, these forces have translated into buyer demands for contracts with lower volumes and greater delivery flexibility.

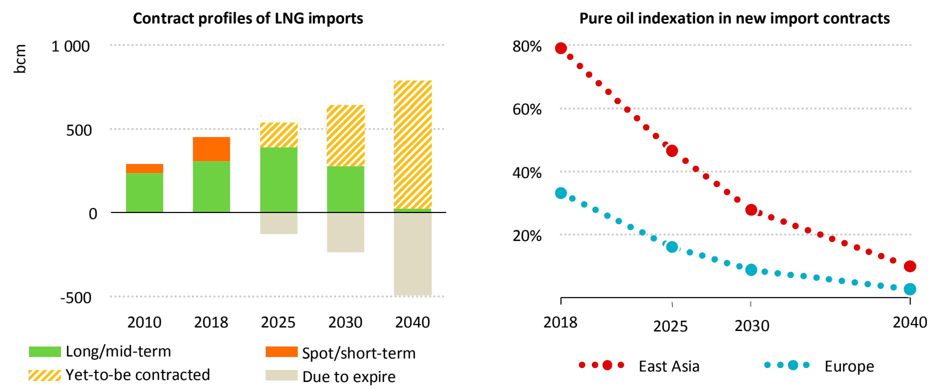
These demands have become increasingly visible in recent contracting trends. The number of new LNG deals signed for volumes of 2 Mtpa or less has grown from 40% of the market in the 2010-14 period to more than two-thirds in the 2015-19 period. Around half of companies buying LNG have a portfolio size no bigger than 2 Mtpa; these buyers represent over 15% of LNG contracts signed in 2015-19, up from about 6% during the previous five years.

The rise in short-term contracts and spot trading has been partly facilitated by floating storage and regasification units (FSRUs), which tend to have relatively low upfront capital requirements, as they are usually leased on a short-term basis rather than purchased. In particular, FSRUs appeal to buyers uncertain of their long-term gas requirements. They also enable near-term needs to be met relatively quickly: Bangladesh and Pakistan are good examples of where FSRUs were used to provide LNG to plug an electricity generation deficit or as a stopgap in the face of a decline in indigenous production. The chartering of FSRUs provides fertile ground for contractual innovation, given the short-term nature of LNG procurement, the involvement of smaller and less creditworthy buyers than in the past, and the need for contract terms to reflect bundled services such as LNG-to-power. In the past three years, however, FSRU chartering activity has slowed, with several projects in emerging markets cancelled or postponed for diverse reasons: some countries are developing their own gas resources and therefore no longer require imports, while others have struggled to secure financing or favourable terms of trade.

More traditional long-term LNG contracts are also gradually being reshaped. Half of all existing LNG contracts, involving some 200 bcm of LNG, are due to expire over the next decade (Figure 4.15). Negotiations for contract extensions seem likely to involve demands for enhanced flexibility, with buyers pointing out that the initial costs of the projects have now been written off, against the background of a regulatory push to remove destination clause restrictions in major LNG importing regions (with continuing efforts in Europe since 2000 and more recent initiatives by Japan and Korea).

Changes in LNG contracts are not without challenges. Buyer demands for seasonal supply conflict with seller needs to market the entire output of a terminal continuously on a long-term basis (although large sellers may be able to balance different seasonal needs across a global portfolio). Meanwhile a growing number of LNG buyers have lower credit ratings than has traditionally been the case, increasing the risks to the seller: nearly 45% of new LNG buyers have a non-investment grade rating or no rating for their default risk.

Figure 4.15 ▷ LNG trade volumes by contract type and assumed oil indexation levels in the Stated Policies Scenario



LNG traded on a spot or short-term basis is increasing as the market opens to new buyers including portfolio traders; pricing increasingly moves away from oil linkage

Notes: Long/mid-term contracts are those longer than three years. Contract volumes include those sold by LNG suppliers on the primary market, net of secondary sales e.g. by portfolio players. "Pure" indexation refers to a situation where over 80% of the price of gas sold under a sales contract is determined through a linkage to the price of crude oil or oil products.

LNG pricing trends

Historically, gas has been priced in relation to oil, providing a reliable reference price for large-scale investments in upstream projects, transport pipelines and LNG terminals. As discussed, there are forces at work to separate gas and oil markets, but around 45% of internationally traded gas today remains based on some form of oil indexation (IGU, 2019). The use of oil indexation varies considerably by region. In North America, gas prices are dictated by the fundamentals of supply and demand as a result of competition between multiple sellers and buyers interacting in a spot market and continuously trading on both physical and virtual hubs. This is commonly referred to as "gas-on-gas competition". European prices, by contrast, are determined by a mixture of gas-on-gas competition and oil indexation, while the dominant pricing mechanism in Asia remains oil indexation, with only a small portion of gas traded on the short-term spot market.

Oil indexation levels are expected to diminish over the outlook period, due to a number of mutually reinforcing developments. The growth of destination-flexible, hub-priced LNG exports from the United States is already providing the catalyst for a more liquid global gas market. The concurrent rise in traders and portfolio players, along with the relaxation of destination clause restrictions, facilitates short-term optimisation of LNG volumes based on arbitrage opportunities. This further supports the rise of a spot market, which becomes increasingly important as a backstop for contractual surpluses and deficits as the supply of international LNG grows.

Over time, the Stated Policies Scenario sees spot gas prices in Europe and Asia settle in a range between the short-run marginal cost of importing LNG from the United States ($4-7/MBtu over the projection period) and the global long-run marginal costs of developing new LNG export projects around the world (at a weighted average cost of $7.50/MBtu, rising above $10/MBtu by the end of the projection period). As the oil price rises, buyers locked into oil-indexed gas contracts pay $9-13/MBtu for their gas imports (depending on contract "slopes" that dictate the strength of the oil-gas price link), and this is likely to expedite contractual renegotiations that incorporate a more diverse set of pricing benchmarks. The rise in such hybrid pricing structures linked to multiple indices allows for a more even spread of market risk between buyers, sellers and traders. As interregional LNG trade grows and increasingly pivots toward Asia, there is further impetus to develop more liquid and transparent pricing references that can help financing for new LNG infrastructure. This, in turn, encourages an acceleration of domestic gas market reforms in several emerging Asian economies, allowing for third-party access to infrastructure to promote downstream competition.

These conditions give rise to a scenario in which the price of LNG, and gas more generally, is increasingly determined by its own supply-demand fundamentals, rather than linked to the price of oil or any competing fuel. Over time, the dominance of oil indexation in new import contracts recedes (Figure 4.15). In the Stated Policies Scenario, less than 20% of LNG trade worldwide remains based on oil indexation by 2040, mostly representing legacy contracts concluded before the mid-2020s.

The LNG business has evolved substantially over the past years, with an increasing roster of suppliers and buyers. However, there are limits to the extent to which LNG, and natural gas more generally, can become a global commodity similar to oil. LNG requires large-scale shipping and costly liquefaction and regasification infrastructure, and gas is more expensive to store than oil or coal. In the Stated Policies Scenario, around 10% of global natural gas supply is liquefied and transported by sea, and two-thirds of this gas remains contracted under long-term, point-to-point delivery arrangements. The scale of upstream gas resources and the financial resources required to sanction an LNG project biases the playing field in favour of larger, well-capitalised sellers and buyers.

However, a key element in LNG's growth story is the ability of sellers to offer more flexible terms to a new wave of buyers, and to allow for innovation in contracting and pricing arrangements to accommodate the rising liquidity and availability of LNG. Several traditional elements of the LNG business seem likely to endure, but are set to co-exist with these more novel elements as the sector continues to evolve.

Box 4.2 ▹ Technologies to minimise emissions from LNG supply

In the Stated Policies Scenario, 80% of the growth in global gas trade to 2040 comes in the form of LNG, with the majority making its way to Asia. Therefore, the indirect emissions arising from the production, transport and delivery of LNG are set to rise significantly.

Liquefying gas is an energy-intensive process and therefore often emissions intensive. Around 10% of gas is consumed as part of the liquefaction process, with most of this being used to power the equipment used to cool that gas to minus 162 degrees Celsius. Pipeline transport also results in emissions (gas is used in compressor stations along the pipeline and in some cases the losses arising from ageing transmission lines are significant), but globally LNG transport, on average, is more emissions intensive than pipeline transport.

A key way to reduce indirect emissions arising along the LNG supply chain (apart from efforts to minimise methane leaks, which are very important, but not specific to LNG) is to electrify the liquefaction process using low-carbon electricity. This would eliminate nearly all of the emissions associated with liquefaction, and lead to a 40% average reduction in greenhouse gas (GHG) emissions from coal-to-gas switching for the production of heat, compared with a 30% reduction if these mitigation strategies were not in place. There is one electric LNG plant currently in operation (the Snøhvit facility in the Norwegian Sea) and others are under construction or under consideration (Freeport LNG in Texas, as well as a number of projects in Canada, such as LNG Canada, Woodfibre and Kitimat). If all the world's existing liquefaction facilities were electrified using zero-carbon electricity, it would reduce annual emissions from the LNG supply chain by 80 million tonnes of CO_2.

Can new LNG technologies create "unconventional demand"?

In recent years, there has been growing interest in the potential for small-scale LNG to unlock new markets and applications for natural gas. Small-scale LNG refers to the use of LNG as a liquid fuel in a number of niche applications for which pipeline gas is unsuitable. Close to 30 Mtpa of small-scale LNG capacity is estimated to be in place, with the vast majority in China (White and Brooks, 2018).

Small-scale LNG has potential uses as a marine fuel for ships and bunkers (see Spotlight), as a liquid fuel for trucks and rail, and as a fuel for use in remote locations that are not served by gas infrastructure (a prime example being oil-based electricity generation in remote off-grid locations). Small-scale LNG also provides an opportunity to underpin a broader transition to natural gas by building new customer bases for the use of LNG that in time could justify the construction of large-scale pipeline infrastructure.

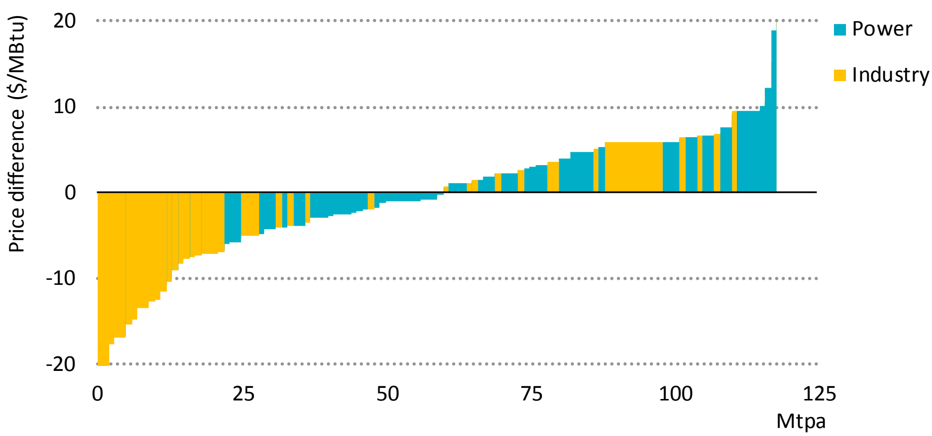
The use of small-scale LNG in various forms is growing in a number of places. In Europe, regasification facility operators have doubled the number of LNG truck-loading services and tripled the number of bunkering facilities over the last five years. More than three-quarters of European regasification terminals now possess truck-loading capabilities, and this has encouraged the expansion of associated infrastructure such as refuelling stations (Gas Infrastructure Europe, 2018). China has quickly developed LNG transportation infrastructure in the form of both trucks and inland bunkering facilities. There are now nearly 300 000 LNG-fuelled trucks in China, a ten-fold increase in four years. Nearly 25 million tonnes of small-scale LNG was delivered in China in 2018 (accounting for around 50% of total Chinese LNG demand), around half of which was sourced from regasification terminals and the rest from small-scale inland liquefaction facilities.

Elsewhere in the world, developing supply chains for small-scale LNG is more challenging, but the potential is high. Figure 4.16 compares the competitiveness of small-scale LNG versus oil products in medium-size industries and for baseload electricity generation. The costs of small-scale LNG lie in a relatively wide range of $2.5-8.5/MBtu, and largely depend on the presence of existing LNG infrastructure, in particular LNG liquefaction or regasification terminals with truck-loading capabilities. Receiving terminals would need to be either FSRUs or otherwise offer "break bulk" capabilities, which could parcel out smaller quantities for local industrial demand; storage tanks would also enable peak shaving in the power sector. Trucking LNG further inland would entail additional costs as well as logistical challenges: for example, a 100 megawatt (MW) baseload power plant would require, on average, around 20 daily deliveries from tanker trucks.

Using the average price of crude oil in 2018 of $70/barrel, up to 60 Mtpa worth of small-scale LNG could be delivered at a lower cost to end-users than oil products. While the substitution potential is only a fraction of oil demand in these sectors, it represents a sizeable 25% of the global LNG market. Around 40% of the global potential lies in developing Asian markets, where gas is around 20-40% cheaper than heavy fuel oil and diesel for industrial consumers. Substitution is costlier in the Middle East, where small-scale LNG fails to compete with highly subsidised oil product prices. Moreover, although the region has significant oil-fired electricity generation, less than a third of plants there are commercially suited to small-scale LNG (i.e. have a capacity less than 300 MW).

Although the potential for cost-effective substitution is high, there are logistical and other hurdles to using small-scale LNG. Lower fuel costs and improved efficiency might be offset by the additional capital expenditure required for converting equipment, which is site- and process-specific. Relatively high storage costs and boil-off rates are also important considerations, which makes the economics of delivering small-scale LNG-to-power plants challenging for plants running intermittently, e.g. as back-up or for peaking purposes. In developing markets, affordability and logistical concerns have discouraged some potential buyers from contracting what are relatively small quantities of flexible supply that need to be delivered on short-term contracts. In addition, while a growing spot market and an expanding list of intermediaries such as trading houses can support small-scale LNG projects, contracting and financing challenges have led to projects being cancelled or delayed.

Figure 4.16 ⊳ Fuel cost competitiveness of small-scale LNG versus oil products for stationary uses, 2018



Up to 60 Mtpa of small-scale LNG could be delivered at a lower cost than oil products that are used for electricity generation and in medium-size industries

Note: Price differences based on an assessment of end-user prices for both gas and oil products that are paid by industrial customers and power plant operators in different countries around the world, taking into account the costs of building small-scale LNG infrastructure, which is a crucial prerequisite for substitution.

In the Stated Policies Scenario, natural gas captures almost 40% of the growth in industrial energy demand in emerging economies, reflecting the economic case for natural gas to satisfy incremental demand that otherwise would be met by costlier oil products, particularly in small- and medium-scale manufacturing subsectors. Traditional large-scale onshore regasification facilities and the build out of transmission and distribution networks underpin the majority of this growth: small-scale LNG is likely to remain a niche part of the global gas market, with its development potential driven by smaller players serving peripheral demand in end-use markets.

S P O T L I G H T

Can LNG sink emissions in maritime shipping?

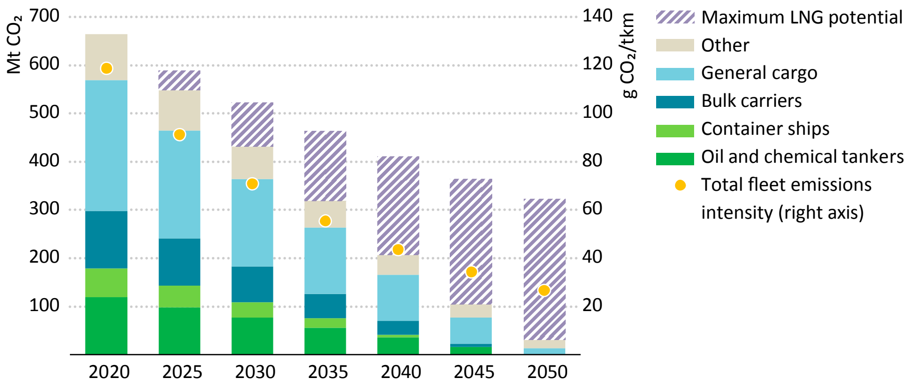
The International Maritime Organization (IMO) sulfur cap, which enters into force in January 2020, has generated interest in using LNG as an alternative to high-sulfur fuel oil in maritime transport. LNG emits almost no sulfur dioxide or particulate matter, and contains up to 90% fewer nitrogen impurities than heavy fuel oil. For shipping companies, LNG is one choice among a range of options to comply with the IMO sulfur regulation, with scrubbers or low-sulfur fuels seen as the main alternatives. There are currently around 130 orders for new LNG-fuelled ships: two-thirds of these are due to be based in Europe, where bunkering infrastructure is currently the most developed. While this would double the global size of the existing fleet, it represents only around 4% of the total order book for new vessels.

In the Stated Policies Scenario, the use of LNG in international shipping reaches 50 bcm by 2040 from less than 1 bcm today, and accounts for 13% of shipping fuel mix. In the Sustainable Development Scenario, whether LNG in shipping has a role to play depends on its ability to reduce GHG emissions. The international shipping sector was responsible for around 700 million tonnes (Mt) of CO_2 emissions in 2018 (2% of global energy-related CO_2 emissions). The IMO has adopted an initial strategy to cut GHG emissions in 2050 by at least half compared to 2008 levels. While the Stated Policies Scenario includes future IMO mandates on sulfur, nitrogen oxide emissions and energy efficiency, it does not include its GHG target for 2050 because details of its implementation have yet to be defined. However, with vessels expected to be in service for up to 30 years, shippers are already thinking about ways to make substantial reductions to emissions intensity.

Burning LNG as a bunker fuel is estimated to achieve at best a 20% reduction in CO_2-equivalent direct emissions compared to fuel oils (Speirs et al., 2019). Assuming scrappage rates consistent with historical averages, "locked-in" carbon emissions from the existing fleet (including vessels on order) would be around 30 Mt CO_2 in 2050. This is some 290 Mt CO_2 less than the maximum level of emissions consistent with the IMO target. In the highly unlikely event of all new ships being powered either by zero-carbon fuels or by LNG, then all of the 290 Mt CO_2 could potentially be emitted by LNG-fuelled ships (Figure 4.17). This translates into a hypothetical upper-bound for annual LNG bunkering of around 100 bcm, or roughly 30% of global LNG trade in 2018.

The extent to which LNG-fuelled ships can maximise this potential, however, is clouded by uncertainty about the overall emission benefits. A comprehensive assessment must consider "well-to-wake" emissions, which combines GHG emissions that can occur upstream before the LNG reaches the ship (i.e. "well-to-tank"), and emissions from methane slip, where gas is not fully combusted in a ship engine and escapes into the atmosphere (i.e. "tank-to-wake"). We assess the average upstream emissions intensity of LNG to be around 160 grammes of CO_2 per kilowatt-hour (g CO_2/kWh), while the extent of methane slip can vary considerably depending on engine performance and dynamic conditions (such as weather). We estimate that, on average, the GHG benefits of utilising LNG as a maritime fuel compared to marine diesel are neutralised once total fugitive methane emissions exceed 4% of a ship's gas consumption.

Figure 4.17 ▷ Locked-in emissions from international shipping and the maximum potential remaining emissions from LNG



As the current shipping fleet is scrapped, demand growth for LNG as a bunker fuel would be limited to around 100 bcm if the 2050 IMO target is to be met

Notes: Mt CO_2 = million tonnes of carbon dioxide; g CO_2/tkm = grammes of carbon dioxide per tonne kilometre.

In the Stated Policies Scenario, the focus for ship operators is principally on the 2020 sulfur cap, for which LNG offers an established and proven option, as well as a reasonable hedge against a tightening of future environmental regulations. In the Sustainable Development Scenario, the focus is more on long-term emissions reduction targets, and here the contribution of LNG is less certain. In this scenario, the overall fleet must accommodate a projected doubling of shipping activity to 2050, while simultaneously achieving a near 80% reduction in the average amount of CO_2 emitted per tonne kilometre. Maximising the potential for LNG in this context depends on a significant uptake of zero-carbon options to fill the sizeable gap between maximum allowable emissions and total shipping activity (as shown by the total fleet emissions intensity in Figure 4.17). Overall, LNG is not a silver bullet, but it could play a role along with other options in helping to reduce emissions in maritime shipping.

4.7 Understanding the global potential for coal-to-gas switching

The substitution of one fuel by another is a fundamental part of energy system change. The shares of fuels in the global energy balance have undergone several important shifts throughout history, notably the transition from biomass to coal during the Industrial

Revolution, and from coal to oil and gas in the 20th century. A new transition is now underway to low- or zero-carbon fuels. It is in this context that we examine the global potential for coal-to-gas switching.

Natural gas is the cleanest burning fossil fuel. Combustion results in around 40% fewer CO_2 emissions relative to coal and 20% fewer than oil for each unit of energy output. Natural gas also emits fewer air pollutants, giving it the potential to improve air quality rapidly when substituting for other combustible fuels. Methane leaks to the atmosphere along the oil, gas and coal value chains are a very important part of the picture, but we find that in the majority of cases, gas is preferable to both oil and coal even when taking into account the full spectrum of emissions arising from extraction, transport and end-use (IEA, 2019b).

Some of the prospects for gas to challenge oil in both stationary applications and in maritime and road transport are explored in the previous section. The focus here is on the opportunities and limits for gas to gain ground at the expense of coal, and in which timeframes and sectors this might apply.

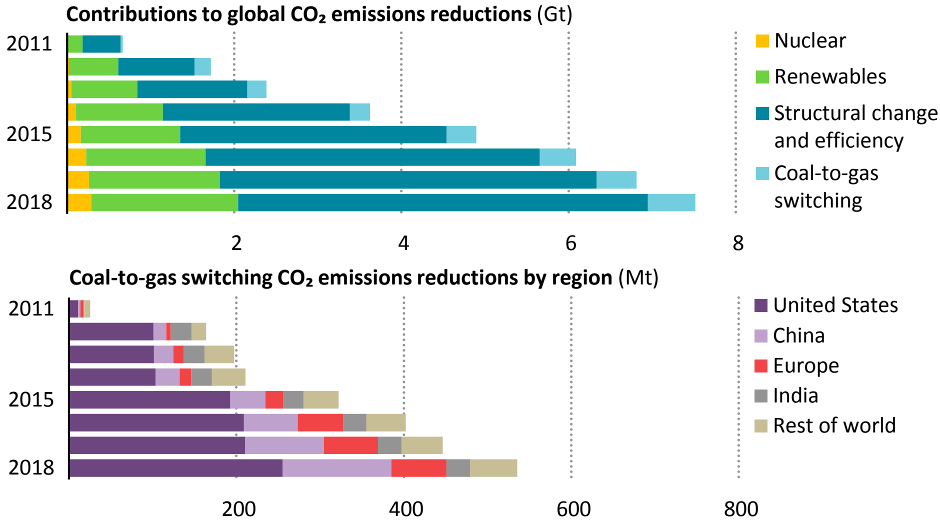
Near-term opportunities for natural gas

The clearest case for switching from coal to gas arises when there is the possibility of using existing infrastructure to provide the same energy services but with lower emissions. The power sector – where 40% of gas and 60% of coal is consumed – is the main arena for competition between the two fuels. Nearly 10 gigatonnes (Gt) of CO_2 emissions, around one-third of global energy sector emissions, come from coal-fired electricity generation, making this by far the largest single category of CO_2 emissions.

Since 2010, we estimate that over 500 Mt of CO_2 emissions have been avoided due to coal-to-gas switching (Figure 4.18). Two-thirds of these savings have occurred in the power sector, reflecting the lower emissions from gas-fired electricity (which is around half that of coal on a lifecycle basis). The largest savings occurred in the United States, where the rise of shale gas has pushed down natural gas prices and underpinned large-scale switching in the power sector, where emissions have dropped by a fifth since 2010. The shale revolution has also had implications for switching in other regions, with rising US exports of LNG helping to push spot gas prices in Europe from over $8/MBtu in 2018 to below $4/MBtu, at times in 2019, thereby improving the economics of gas-fired electricity generation.

Switching from coal to gas in the European Union (EU) has also been supported by policy interventions. In the United Kingdom, coal-to-gas switching has contributed to a 55% drop in the emissions intensity of electricity generation following the introduction of a carbon price floor in 2013: this imposed a minimum cost to generators of GBP 9/tonne CO_2, which was doubled in 2015. The EU's Emissions Trading System (ETS) has been reformed to eliminate surplus allowances from the market: this has pushed up the ETS price from an average of EUR 5/tonne CO_2 in 2016 to over EUR 20/tonne CO_2 in late 2018, helping to tip the balance of short-run generating costs in favour of gas over coal. Coal-fired power plants have also been affected by stricter EU directives governing pollution from large combustion plants, and national policies to phase out coal generation in several European countries.

Figure 4.18 ▷ CO_2 emissions reductions since 2010



Coal-to-gas switching has prevented over 500 Mt CO_2 of emissions since 2010. More than two-thirds of the savings have taken place in the United States and China.

Note: Structural change and efficiency shows emissions savings compared to a baseline that assumes no further improvements in the energy and CO_2 intensities of gross domestic product since 2010.

In 2019, coal, gas and carbon prices in the European Union have at times been at levels that place more than three-quarters of the EU's gas-fired generation capacity within a competitive range for coal-to-gas switching. Ultimately, the extent to which gas displaces coal in practice depends on daily electricity demand profiles, fuel contracting patterns as well as on the extent of renewable-based generation: the accelerating pace of wind and solar output in several key markets is set to shrink the space in which coal and gas compete for market share.

Policies are also driving coal-to-gas switching in China, where the main motivation is to improve air quality and the main sectors involved are industry and buildings rather than power. Given the continued growth in energy demand, a high priority is being given to building new gas infrastructure, even though imported gas is relatively expensive. Nearly 9 million additional households switched from coal to natural gas or electricity for heating in 2017/18, with a further 3 million conversions planned to be completed by 2021. China's National Energy Administration is also seeking to expand biogas production to promote rural coal-to-gas switching. It aims for production to reach 30 bcm by 2030 (from around 10 bcm today).

The example of China highlights that, in many gas-importing countries in Asia, gas needs a supporting policy push in order to displace coal. It also highlights that, in a world of ever-cheaper renewables, gas does not necessarily represent the major challenger to baseload coal in Asia's electricity generation. In India, gas currently has a low share of the energy mix (as in China), and there has been very little evidence of switching to gas so far. Plans to expand city gas distribution grids in India, if realised, would make gas far more widely available, but the economics would not appear to favour replacing coal with gas in power and industry; instead, gas may displace liquefied petroleum gas (LPG) as a cooking fuel, and oil as a fuel in some parts of the transport and industry sectors.

In many countries in Southeast Asia, the immediate gains from switching from coal to gas are only feasible with very low gas prices. Given the relatively young and modern fleet of coal-fired plants and the low cost of indigenous coal, gas prices would need to drop to a range between $2-4/MBtu to create a commercial case for switching – which in many cases is below the long-run marginal cost of domestic supply – and well below the cost of LNG imports (Figure 4.12).

Box 4.3 ▷ How does carbon pricing affect the switching calculation?

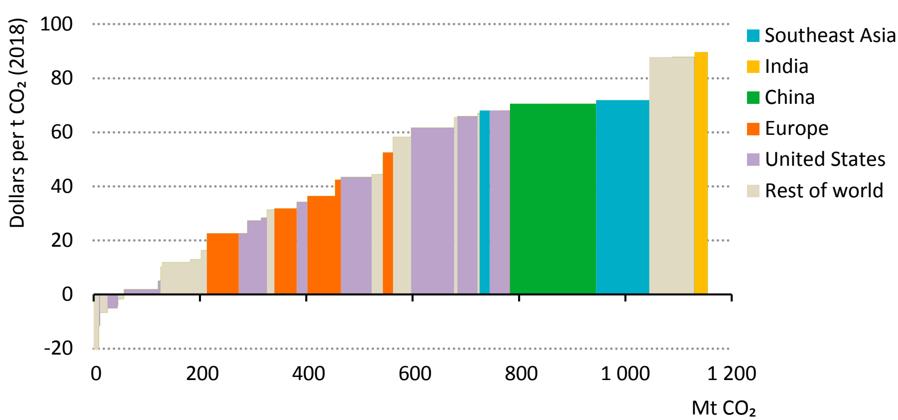
Commodity prices for coal and gas paid by utilities today mean that most of the switching potential identified in our analysis is out of reach. However, this could change if a higher price was put on CO_2 emissions. The size, location and relative efficiencies of existing coal and gas-fired power plants are key determinants of the technical and economic potential for a carbon price to lead to a switch from higher to lower emitting units. Power systems designed around a merit order whereby plants are dispatched according to their short-run marginal costs of generation are a crucial prerequisite for allowing gas plants to run ahead of coal if relative prices are favourable.

Globally, a price of $60/tonne of CO_2 could trigger nearly 700 Mt CO_2 in avoided emissions from coal-to-gas switching in electricity generation using existing infrastructure and our commodity price assumptions in the Stated Policies Scenario in 2025 (Figure 4.19). In the United States, significant gains from switching could be achieved with an average carbon price of $40/tonne CO_2. In Europe, savings from switching could be unlocked once carbon prices exceed $22/tonne CO_2 (EUR 20/tonne CO_2); the ETS has been around this level since early 2019, supporting an increase in gas-fired generation.

China's emerging carbon market may offer a similar opening for natural gas to gain market share. However, with a cost gap between coal and gas-fired electricity generation of $30-40 per megawatt-hour, a CO_2 price in the $60-80/tonne CO_2 range would be needed to provide enough support for switching to gas. Similar conditions prevail in Southeast Asia, where a carbon price averaging $70/tonne CO_2 could result in savings of some 120 Mt CO_2, or around 20% of Southeast Asia's total power sector CO_2 emissions. In markets such as India, where high gas prices have led to stranded gas-fired power plants, carbon prices would have to average $90/tonne CO_2 to stimulate switching.

Carbon prices can also affect the investment case for new natural gas plants as compared with renewables or other technologies such as nuclear, battery storage or carbon capture, all of which present alternatives to the use of gas to reduce emissions in the power sector. The costs of wind and solar technologies in particular are falling considerably, bolstering the economic case for switching directly from coal to renewables. However, there are other factors that bear on the investment calculation. Power systems typically need a certain proportion of baseload, mid-merit and peaking plants to meet variable levels of demand: the extent to which gas, renewables or other power technologies can meet these demands, in addition to providing services such as flexibility and standby capacity, is an important consideration. Moreover, while the cost of carbon stimulates investment by influencing the wholesale power price, new gas-fired power plants and renewable energy projects often derive much of their revenue from outside the wholesale power market. A carbon price therefore is one of a range of considerations that will determine the role of gas in future power systems.

Figure 4.19 ⊳ Average cost of potential emissions savings from coal-to-gas switching in the power sector, 2025



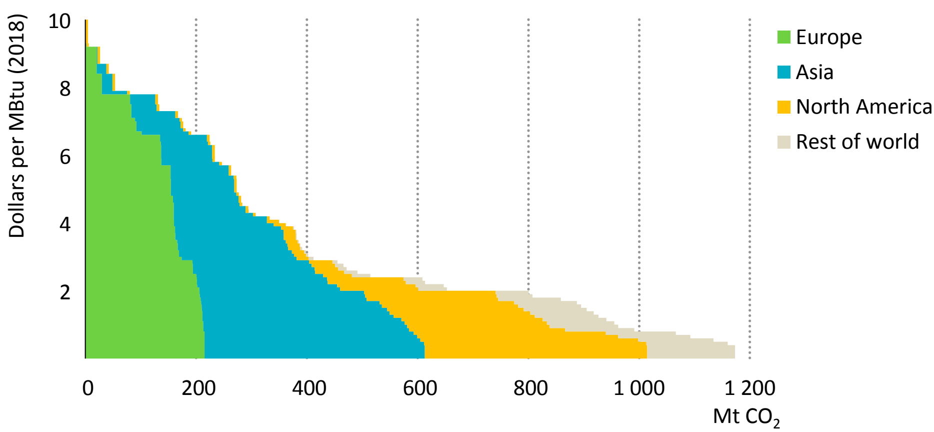
Carbon prices needed to trigger switching differ around the world; most low-cost potential is in Europe and the US which have older coal plants and spare gas capacity

Notes: Average delivered cost to power plants (gas / coal per MBtu) with no carbon price applied: United States: \$9 / \$3; European Union: \$35 / \$11; China: \$44 / \$17; India: \$41 / \$10. The United States is broken down by regional independent system operators.

Taking full advantage of near-term opportunities for switching in the power sector, based on existing infrastructure would yield global CO_2 savings of around 1 200 Mt CO_2 (Figure 4.20). Most of the realisable potential is in the European Union and the United States. With relatively slow electricity demand growth, ample gas and power infrastructure and significant spare gas capacity, these markets could displace around half of their respective coal-fired power output.

Elsewhere in the world most of the switching potential is not economic at current commodity prices. The overall economic potential for switching in much of Asia is limited by the efficiency of the relatively young coal-fired power fleet. In China, for example, the share of supercritical and ultra-supercritical coal plants within the fleet increased from 3% in 2005 to almost 40% in 2018, and plants have modernised quickly, adapting to stricter regulations governing air pollutant emissions. Since the gas fleet is less than one-tenth the size of the coal fleet in China, the current savings potential from switching (around 100 Mt CO_2) is in any case small relative to its overall power sector emissions (4 900 Mt CO_2). With the absence of a carbon price and a coal price in the range of $60-80/tonne, the delivered cost of gas to most utilities in Asia would need to be below $4/MBtu to stimulate switching, compared with an average price for imported LNG in 2018 of $9.50/MBtu. Falling spot prices in 2019 have placed some gas plants in a more competitive position, but a positive differential for gas would need be sustained over a longer period to effect a more durable shift away from coal.

Figure 4.20 ▻ Potential CO_2 savings from coal-to-gas switching at various gas prices using existing power plants



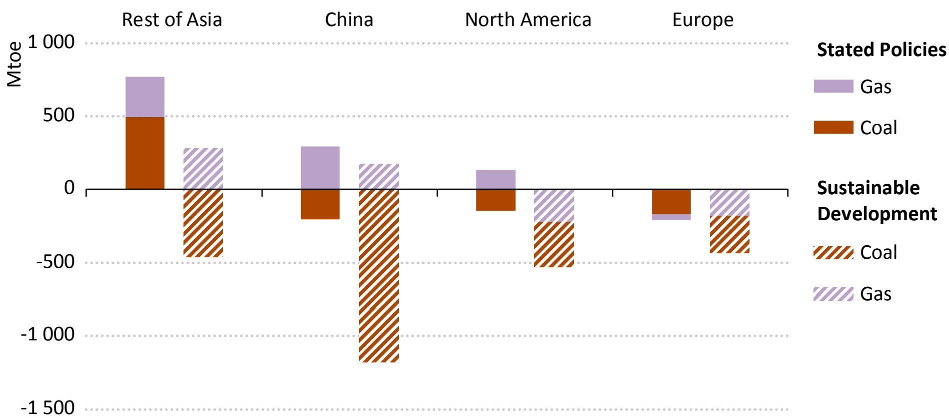
Rising carbon prices mean gas-fired power plants in Europe are competitive with coal, whereas most Asian markets require much lower gas prices – less than half of 2018 levels

Is coal-to-gas switching a viable long-term route to emissions reductions?

In the Stated Policies Scenario, gas use increases by an average of 1.4% each year through to 2040 and helps to meet existing energy policy commitments and ambitions. However, this scenario puts energy-related CO_2 emissions on an upward trend to 2040, far from the emissions trajectory required to tackle climate change. In the Sustainable Development Scenario, renewables and efficiency measures are the most important drivers of the energy sector transition. Natural gas plays a role in this scenario, although the extent varies by country, sector and timeframe.

In mature natural gas markets, like the United States and Europe, coal-to-gas switching is a compelling near-term option for reducing emissions, given existing infrastructure and spare capacity. Gas can also contribute to security of electricity supply by balancing variable renewables and meeting peaks in demand. However, given the need for decarbonisation efforts to intensify in the Sustainable Development Scenario, a role for unabated gas in the energy mix becomes increasingly challenging in this scenario: by 2040, gas demand is 40% lower than today's levels in Europe and 25% lower in the United States (Figure 4.21). The case for natural gas is also challenged by increasing investments in battery storage and grid management capabilities, which, if scaled up, could fulfil the same short-term flexibility functions as gas-fired power plants.

Figure 4.21 ▹ Change in gas and coal demand by scenario, 2018-2040



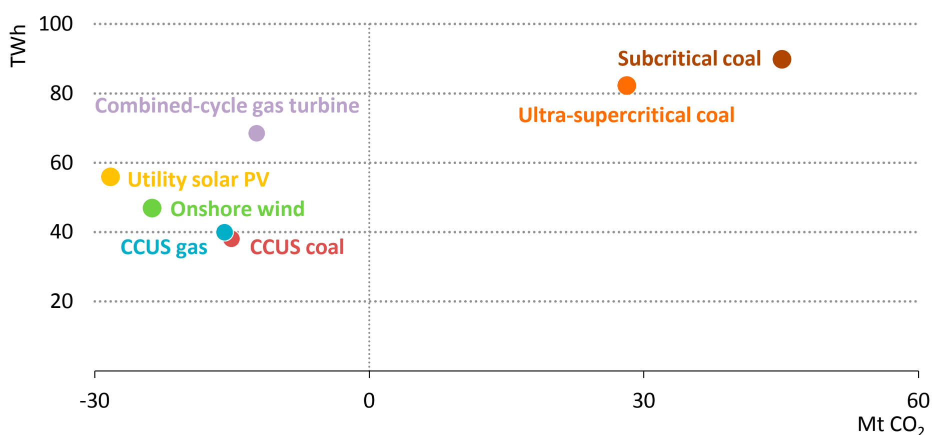
Gas plays a role in reducing coal demand in the Sustainable Development Scenario in Asia, while in North America and Europe both gas and coal are pushed out of the mix

Gas plays a more pronounced role in developing economies that are very carbon-intensive today, helping to push more polluting fuels out of the energy system. Gas demand in China is lower in the Sustainable Development Scenario, but still helps to displace coal demand in both power and industry, while in India gas demand is even higher than in the Stated Policies Scenario as gas replaces coal as a baseload source of electricity generation.

The long-term growth opportunities for gas in the electricity generation mix in Asia depend heavily on policy priorities in each country. Southeast Asia, where the demand for electricity is rising robustly, offers an illustration of the challenges facing gas as a lower emissions option than coal for providing power. Until recently, natural gas was the largest source of electricity generation in the region. However, several countries are now turning to coal, partly due to slowing or declining domestic gas production. Coal is plentiful and available at low cost and foreign direct investment has supported new coal capacity additions. In the Stated Policies Scenario, power sector emissions in Southeast Asia double, as natural gas cedes market share to coal while renewables, despite tripling, covers barely 40% of total electricity demand growth in the period to 2040.

While renewables offer a compelling pathway to long-term emissions reductions, investing in gas-fired power as a baseload source of generation in place of coal can also help reduce emissions. Figure 4.22 compares the emissions and generation performance for different power technologies under an illustrative $5 billion investment in Southeast Asia, taking into account capital, operating and fuel costs over a 30-year asset lifetime. If the priority is to maximise electricity output, then coal comes out on top (as it does for this region in the Stated Policies Scenario). Subcritical coal plants in particular remain among the cheapest generation options given lower fuel costs. More expensive ultra-supercritical coal plants yield lower emissions than subcritical plants, but their emissions per unit of power output are higher than the average emissions intensity of total generation in 2018 for the region as a whole (around 510 g CO_2/kWh, which is the baseline in Figure 4.22). If the priority is to lower this average, then wind or utility-scale solar offer larger long-term emissions savings than gas-fired combined-cycle gas turbine (CCGT) plants. Gas is therefore a second-best option, both in terms of environmental performance and power output.

Figure 4.22 ▷ Cumulative effects on electricity generation and emissions in Southeast Asia of spending $5 billion in the power sector



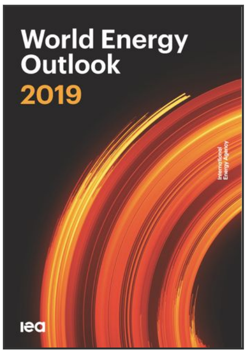
The highest efficiency coal plants still negatively impact average emissions in the region; gas brings improvements, but wind and solar provide more than twice the savings

Notes: TWh = terawatt-hours; CCGT = combined-cycle gas turbine; CCUS = carbon capture, utilisation and storage. Spending equals total capital and operating expenditure over a thirty-year investment period starting in 2020 and including construction lead times. Load factors for thermal power plants = 60%; wind = 24%; solar PV = 13%. CCUS capture rates assumed to be 90%. The change in emissions is compared to generating the same amount of electricity with the average emissions intensity of electricity generation in Southeast Asia in 2018.

The investment case for wind and solar capacity, however, is complicated by the variability of their generation profiles, which creates challenges for ensuring electricity system stability. Gas and coal plants have an advantage since they are dispatchable sources of electricity generation. In this regard, they can provide standby capacity to balance the variability of renewable output or, if equipped with carbon capture, utilisation and storage (CCUS), ensure stable baseload supply while also delivering significant emissions reductions.

A crucial variable for the future that could change the prospects for both gas and coal is the extent to which CCUS technologies are deployed. However, retrofitting existing plants would require large upfront capital costs and relatively long construction lead times. As for new plants, the finite amount of capital available for new generation capacity in the illustrative investment case would cover the installation of 250 MW of gas-based CCUS capacity compared with 500 MW of conventional gas turbine capacity. Taking into account the average emissions intensity for the power fleet as a whole, this means overall CO_2 emissions savings for new, conventional gas plants would be similar to CCUS units over the 30-year investment horizon.

While coal-to-gas switching is not the long-term answer to climate change, it is one of a portfolio of options to reduce emissions across a broad range of sectors, helping to bring down emissions in the short term, while providing valuable flexibility to power systems with growing shares of variable renewable energy sources. In the Sustainable Development Scenario, renewables and efficiency do the heavy lifting, while coal-to-gas switching contributes around 8% of the overall emissions savings required in the 2018-40 period.



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